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Modelling the interactions between power systems and energy systems

Thesis presented by

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Declaration

This is to certify that the work I, Seán Collins, am submitting is my own and has not been submitted for another degree, either at University College Cork or elsewhere. All external references and sources are clearly acknowledged and identified within the contents. I have read and understood the regulations of University College Cork concerning plagiarism.

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Seán Collins

Acknowledgements

Research is, by its very nature, a collaborative process and this thesis is no exception.

First and foremost, I would like to thank Professor Brian Ó Gallachóir and Dr Paul Deane for their guidance and support at all stages of my research. They both were an invaluable source of help throughout and I am very grateful.

Secondly, I would like to thank everyone I have collaborated with as part of this thesis. These collaborations entailed many long and fruitful discussions, and numerous email chains that were longer than I knew possible. Specifically I would like to thank Dr Kris Poncelet and Dr Erik Delarue of the Katholieke Universiteit Leuven, Dr Evangelos Panos of the Paul Scherrer Institute, Dr Robert Pietzcker of the Potsdam Institute for Climate Impact Research, Mr Fiac Gaffney of University College Cork, Dr Stefan Pfenninger of ETH Zürich, Dr Iain Staffell of Imperial College London, Dr Deger Saygin, Dr Asami Miketa, Ms Laura Gutierrez and Dr Dolf Gielen of the Innovation and Technology Centre of the International Renewable Energy Agency.

I would also like to thank everyone past and present at the Environmental Research Institute (ERI). Banter-filled discussion at the lunch table really helped with my work by allowing me to escape from it. There are truly so many people who have made this possible that I would be unable to mention them all. Special thanks though must be given to members of the energy policy and modelling group with whom I have worked and played to varying degrees these past few years: Eamonn Mulholland, Fionn Rogan, James Glynn, Alessandro Chiodi, Matthew Clancy, Fiac Gaffney, Tomás Mac Uidhir, Peter Deeney, Xiufeng Yue, Emma Hanley, Maitiú Ó Ciaráin, Mitra Kami Delivand, Evan Boyle, Clare Watson, Alessia Elia, Conor Hickey, Connor McGookin, Laura Mehigan, Tarun Sharma, Maarten Brinkerink, Camella Bailey, Parveen Kumar and Gideon Fadiran.

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Executive Summary

The European Union has significant ambitions to decarbonise the energy system by 2050. The power system is expected to play a key role in this energy transition, with this role involving increased electrification of heat and transport and increased integration of variable renewable electricity. Energy systems models are currently used to inform long-term policy decisions, generating technology pathways for energy system decarbonisation. However, they struggle to sufficiently represent short term characteristics of power system operation, which can lead to over simplified conclusions and misguided policy decisions.

The core aim of this thesis is to use a multi-model approach to improve this representation of short-term power sector operation in long-term energy system planning with a view to gaining a better understanding of the role of electricity in the wider European energy system decarbonisation.

The thesis links detailed operational power systems models to a number of long-term energy planning models and energy planning studies. This leverages the strengths of a heavily interconnected pan-European dispatch model with high technical and temporal resolution. The thesis generates new results and insights that energy systems models struggle to provide, such as interconnector congestion, renewable electricity curtailment and electricity market prices. It also explores the impact of inter-annual wind and solar variations on the future EU power system. It further proposes an approach to determine the renewable electricity share for each Member State based on renewable electricity consumed rather than produced, accounting for international flows of electricity on an hourly basis.

Detailed power systems modelling coupled with long-term energy system planning is shown to allow for sectoral nuances, such as individual generator constraints and flexibility, to be captured which allows for balanced assessment of policy.

The key contributions of this thesis are both the methodological gains and the operational power sector insights attained which when combined allow for better projection of technology pathways for the energy system and more effective energy policy formulation.

Units and Abbreviations

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
AI	All Island
AIM	Asia-Pacific Integrated Model
B	Billion
BOE	Barrel of Oil Equivalent
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CGE	Computable General Equilibrium
CO_2	Carbon Dioxide
DC	Direct Current
DE	Domestic Exports
EC	European Commission
ECF	European Climate Foundation
EEA	European Environmental Agency
EMHIRES	European Meteorological Derived High Resolution Renewable Energy Source
ENTSO-E	European Network of Transmission System Operators for Electricity
EPPA	Emissions Prediction and Policy Analysis
ESOM	Energy System Optimization Model
ETS	Emissions Trading Scheme
ETSAP	The Energy Technology Systems Analysis Program
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
EV	Electric Vehicle
EVPI	Expected Value of Perfect Information
FLh	Full Load Hours
GCAM	Global Change Assessment Model
gCO_2	Gram of CO_2
GET	Global Energy Transitions
GFC	Gross Final Consumption
GFEC	Gross Final Energy Consumption
GHG	Greenhouse Gas
GJ	Gigajoule
GTMax	Generation and Transmission Maximisation Model
GW	Gigawatt
GWh	Gigawatt Hour
hr	Hour
Hz	Hertz

IAEA	International Atomic Energy Agency
IAM	Integrated Assessment Model
IC	Interconnector
IEA	International Energy Agency
IMAGE	Integrated Model to Assess the Global Environment
IRENA	International Renewable Energy Agency
JRC	Joint Research Centre of the European Commission
kgCO2	Kilogram of CO2
kW	Kilowatt
kWh	Kilowatt hour
LDC	Load Duration Curve
LIMES	Long-term Investment Model for the Electricity Sector
LUSYM	Leuven University System Modelling
MACRO	Macroeconomic Model
MARKAL	Market and Allocation
MERGE	Model for Evaluating the Regional and Global Effects of GHG Reduction Policies
MERRA	Modern-Era Retrospective analysis for Research and Applications
MESSAGE	Model for Energy Supply Strategy Alternatives and their General Environmental Impact
MILP	Mixed-Integer Linear Programming
min	Minute
Mt	Megatonne
MW	Mega Watt
MWh	Megawatt Hour
MWs	Megawatt Second
NASA	National Aeronautics and Space Administration
NORDEL	Nordic Electric System Operators
NREL	National Renewable Energy Laboratory
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
ORCED	Oak Ridge Competitive Electricity Dispatch
OSeMOSYS	Open Source Energy Modelling System
PERSEUS-CERT	Programme-package for Emission Reduction Strategies in Energy Use and Supply-Certificate Trading
POLES	Prospective Outlook on Long-term Energy Systems
POTEnCIA	Policy Oriented Tool for Energy and Climate Change Impact Assessment
PRIMES	Price-Induced Market Equilibrium System
PV	Photovoltaic
ReEDS	Regional Energy Deployment System
REF	Reference

REmap	Renewable Energy Roadmap
REMIND	Regional Model of Investments and Development
RES	Renewable Energy Sources
RES-E	Renewable Energy Sourced Electricity
RLDC	Residual Load Duration Curve
RoCoF	Rate of Change of Frequency
s	Second
SEM	Single Electricity Market
STEM-E	Swiss TIMES electricity model
t	Tonne
TIAM	TIMES Integrated Assessment Model
TIMER	Targets IMAGE Energy Regional
TIMES	The Integrated Market Allocation Energy Flow Optimisation Model System
TW	Terawatt
TWh	Terawatt Hour
TYNDP	Ten Year Network Development Plan
UCC	University College Cork
UCED	Unit Commitment and Economic Dispatch
UCL	University College London
UCTE	Union for the Coordination of the Transmission of Electricity
UNFCCC	The United Nations Framework Convention on Climate Change
US-REGEN	United States Regional Economy, Greenhouse Gas, and Energy
VRE	Variable Renewable Energy
VRES-E	Variable Renewable Energy Sourced Electricity
VSS	Value of Stochastic Solution
WE	Wheeled Exports
WITCH	World Induced Technical Change Hybrid

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Chapter 1: Introduction

1.1. Background

In December 2015, a landmark agreement was reached in the 21st annual session of the conference of the parties (COP21) to the United Nations Framework Convention on Climate Change (UNFCCC) which agreed to limit the global increase in temperature due to climate change to “well below 2°C above pre-industrial levels” with a view to pursuing efforts to “limit temperature increase to 1.5°C”. The challenges of achieving this ambition are substantial and approximately two-thirds of the globally available greenhouse gas emissions budget to limit global temperature increase to this 2°C target has already been emitted into the atmosphere (Pachauri et al., 2014). The energy sector is the single biggest source of greenhouse gas emissions and accounts for about two-thirds of these emissions (IEA, 2017b). Thus, climate change mitigation efforts are inextricably linked to energy sector decarbonisation, with CO_2 being the main greenhouse gas emitted in this sector. In a bid to mitigate the harmful effects of climate change there has been a strong uptake in renewable energy across many sectors of the energy system. Climate change mitigation, however, is not the only reason for this uptake.

Renewable energy penetration has also rapidly increased due to cost reductions in renewable energy technologies. In many markets, renewable energy technologies now undercut their fossil-fuelled competitors and are among the cheapest sources of energy available. The rate of cost reduction has been impressive, especially for power generation technologies. The cost of electricity from solar photovoltaic (solar PV) fell by almost three quarters between 2010 and 2017 and that from wind generators has fallen by approximately half over the same period, depending on the market (IRENA, 2018b). These trends are set to continue aided by economies of scale, greater competition, improved manufacturing processes and more competitive procurement. By 2020 all mainstream renewable power generation technologies are anticipated to have average costs that are at the lower end of their fossil-fuelled counterparts. Renewable energy has also been shown to have positive impacts on air quality (Millstein et al., 2017) that lead to significant cost savings which result mostly from the avoidance of premature mortalities. Furthermore, on average, renewable energy technologies have been shown, using project-level data, to facilitate greater job creation that more than offset any job losses from fossil-fuelled technologies (IRENA, 2018a). All these positive attributes of renewable energy have set a global energy transition in motion.

The European Union (EU) is at the forefront of this global energy transition to a decarbonised energy system. The EU has committed to an 80% - 95% reduction in greenhouse gas emissions by 2050 relative to 1990 levels. The overall share of energy from renewable sources nearly doubled between 2005 and 2016 to 17% while the share of renewable energy in the power sector doubled to 30% over the same period (Eurostat, 2017). The EU has also recently reached an ambitious agreement on further renewable energy development that includes a binding renewable energy target for 2030 of 32% with an upwards revision clause by 2023 (European Commission, 2018b). A substantial portion of this increase in European renewable energy penetration will fall to the power sector and will likely lead to an increase in electricity demand (IRENA and European Commission, 2018). However, with much of the hydro capacity already exploited in Europe (European Commission, 2018a) much of this increase in renewable energy will likely be met by wind and solar PV generation. Wind and solar PV are variable renewable sources of electricity generation which pose integration challenges for system operators and planners due to their limited predictability, variability and spatially distributed nature which all pose difficulties when trying to maintain provision of a reliable electricity supply. These concerns make optimal pathways to a highly renewable low carbon future challenging to discern whilst maintaining a detailed representation of power sector operation.

Policy decisions in this regard need to be based on robust analysis to ensure that the most effective course is chosen by policymakers that face binding budgetary and climate constraints. Long-term energy system planning activities that are used to project technology pathways for the entire energy system can struggle to represent short-term power sector operation due to both their wide scope and the computationally intensive modelling required to capture the of short-term variability of power sector operation. Neglecting the short-term variability of the power sector can lead to an under or overestimation of the difficulty of achieving a highly renewable low carbon future. This, in turn, may result in misguided and expensive policy implementation.

The motivation for this thesis is to address these concerns for the European policy development and permitting improved policy formulation by making methodological improvements to and by identifying operational concerns with studies currently underpinning European energy policy. To do so, this thesis establishes the present state of the art in the integration of short-term variability in long-term planning and analyses the evolution of European power sector operation in studies that are presently being used to inform European policy decisions using a soft-linked dispatch modelling and scenario analysis methodology.

1.2. Methodology

Researchers interested in the role of the power sector in overall energy system decarbonisation planning tend to study it from a variety of perspectives. However, such work can often be too narrowly focussed on aims of the study conducted without consideration of the bigger picture. As such this can lead to silo-based assessments which fail to capture a broad range of concerns from which policy decisions can be derived. This thesis aims to address this by combining power system dispatch modelling with a host of analyses by applying a combination of soft-linked dispatch modelling and scenario analysis. This is a process by which the results of one model or study are used as inputs to another more detailed power system model and act as a starting point for further analysis. This process allows for study coupling whereby the results of multiple studies can be analysed by using them as inputs for detailed sectoral modelling. This allowed this thesis to assess the operation of multiple power sector decarbonisation scenarios in combination with long-term energy system modelling, long-term reanalysis modelling, continental transmission system planning and policy development tools.

1.2.1. Soft-Linked Dispatch Modelling

In its simplest form, this modelling approach is one by which the generation mix and electricity demand resulting from one study is analysed in greater detail by using a separate unit commitment and dispatch model. This approach shows how such a system would operate at high technical and temporal resolution and provides insights that complement the study to which it is applied. It provides additional insights such as wholesale pricing, interconnector congestion, cycling of conventional generators, curtailment of variable renewable power and others that are not possible in other studies due to both their scope and the computational power required to perform unit commitment and dispatch simulations.

This thesis builds on a soft-linking approach first outlined by (Deane et al., 2012). This methodology has been used in the past to analyse results for the Irish TIMES model and the Italian MONET model(Deane et al., 2015a, Deane et al., 2015b) where valuable insights in terms of the increased need for power system flexibility were gained. This methodology was also previously geographically expanded to model the regional power system of North-West Europe (Deane et al., 2015d) and identified policy challenges that arise with incoherent national power system planning between European Member States. This thesis expands further on this approach to provide multi-faceted insights into the operation of a transitional low-carbon 30-country European power system using a variety of scenarios and varying input assumptions that are themselves the result of other analyses. This thesis uses one main power system modelling software tool called PLEXOS Integrated Energy Model which is used for integrated least cost optimisation modelling of electricity, gas and water systems worldwide. In this thesis, the modelling platform is used to optimise unit commitment and economic dispatch of the power sector using short-term deterministic modelling. The model minimises the total generation cost of the system while respecting four key constraints: 1) electricity demand and supply must balance; 2) technical characteristics of generators (such as minimum stable levels, ramp rates, minimum up and down times, and maintenance rates); 3) transmission capacity of interconnector lines; 4) forced (random outages based on Monte Carlo simulations) and unforced (scheduled) outages of generators. A perfect day-ahead market is assumed across the EU where there is no market power or anti-competitive bidding behaviour where power stations bid their true short-run marginal cost, all of which impact the reality of power system operation. All simulations undertaken were in line with the EU Target Model day-ahead market-scheduling algorithm, known as EUPHEMIA, where 365 days of the each scenario simulation year were simulated at hourly resolution which thus make all this work representative of the European electricity market function.

1.2.2. Scenario Analysis

Making accurate long-term future projections for anything with absolute certainty is a near impossible task. Energy systems modelling to inform energy policy does not set out to do this but rather seeks to explore various paths for future development without a directly attributed level of probability. Scenario and futures analysis is the process of analysing these possible futures to provide context that can form the basis for broad-based policy decisions by giving a range of possible consequences based on uncertainties.

In this thesis, a multitude of scenarios are analysed and generated by varying the installed generation mix, electricity demand profiles, variable renewable resource profiles and operational power system constraints for the European power system. This is done with a view to informing policy development for European power and energy systems out to 2030. Utilising scenarios using the aforementioned soft-linked approach makes each scenario comparable to each other by being simulated using the same modelling framework. Doing this for the pan European power sector provides a roadmap for future development and allows for powerful insights to be drawn from which balanced energy policy decisions can be made.

1.3. Thesis Aim and Key Research Questions

The overall aim of this thesis is to improve the knowledge base underpinning energy policy development for the European energy system by enabling better capture of the interactions between power systems and energy systems in long-term planning. This led to the identification of the following key research questions that shaped and guided the research of this thesis:

1. What is the present state-of-the-art in accounting for short-term variability[1] of power sector operation in long-term energy planning?
2. What insights are gained by modelling analyses underpinning European energy policy at high technical and temporal resolution for the power sector?
3. What is the influence of the inherent weather dependency of generation on power system operation?
4. How can methodological improvements be used to enable improved energy policy formulation?

[1] Short-term variability here refers to the timescale of factors that influence dispatch planning

Each chapter addresses at least one of these research questions while most answer a variety. This echoes the real nature of energy policy development where there is a myriad of considerations involved in making well-rounded policy. Energy and power system modelling to inform policy must balance and weight various considerations appropriately and this thesis addresses this by considering the challenge of planning energy and power system decarbonisation from a variety of perspectives. Determining decarbonisation pathways for the European energy system whilst ensuring appropriate power sector representation is indeed challenging but this thesis strives to further this capability.

1.4. Thesis in Brief

This thesis is presented in 6 chapters: Chapters 2, 3 and 5 are articles published in peer-reviewed scientific journals for which I am the lead author. Chapter 4 is an article published in a peer-reviewed scientific journal for which I am a co-author. Chapter 6 is an article for which I am lead author that is in late-stage review for publication in a scientific journal. Chapter 7 presents the conclusions of this thesis, and recommendations and suggestions for future work.

Chapter 2 is an in-depth evaluation of prominent methodologies developed to enable improved representation of short-term variability of the power sector in long-term integrated energy systems models. This chapter serves as a methodological roadmap for modellers by comparing methodologies and identifying their strengths and weaknesses that can act as basis for improving power sector representation in long-term energy system planning.

Chapter 3 applies and elaborates on a uni-directional soft-linked methodology assessed in chapter 2 to provide complementary analysis of the power sector results for 2030 for the European Commission's EU Reference scenario derived from the European energy system model, PRIMES. The PRIMES model spans the whole European energy system and currently underpins European energy and climate policy decisions. This chapter provides policy insights by leveraging the strengths of a heavily interconnected pan-European dispatch model with high technical and temporal resolution that uses localised renewables datasets to gain insights into its results.

Chapter 4 proposes a new methodology for determining a country's renewable energy share in electricity and performs an ex-post analysis on the results of the model initially developed in chapter 3. The proposed approach determines the renewable electricity share for each country based on renewable electricity consumed rather than produced in a country (as is done today) by accounting for international flows of electricity on an hourly basis. The methodology this chapter applies would be complex to implement were it to be mandated in energy policy and would likely require the creation of an agency that would remunerate producers from the country that actually consumed their electricity. This serves as a thought-provoking piece that highlights concerns regarding uncoordinated support mechanisms, price distortions and cost inequality in the European electricity sector in 2030 derived from high resolution pan European dispatch modelling using localised wind and solar profiles.

Chapter 5 is a long-term multi-scenario dispatch analysis of the European power sector that studies, using highly resolved long-term wind and solar datasets, how long-term wind and solar variability impacts the operation of the European power system and how these impacts vary with decarbonisation ambition. This is done by expanding the model developed in chapter 3 to include a wider range of decarbonisation scenarios with varying levels of electrification of transport and heating sectors, and to run based on 30 years of scenario-specific localised historic hourly wind and solar profiles. The scenarios used, which were developed by both the European transmission system operator, ENTSO-E, and the European Commission[2], are underpinning European energy policy decisions. This chapter analyses their results using a highly interconnected dispatch model cognisant of the long-term variability of wind and solar generation sources that are likely to underpin European power system decarbonisation.

Chapter 6 performs a dispatch analysis of the International Renewable Energy Agency's policy tool, REmap, which is used to inform energy policy development worldwide. REmap is a transparent and straightforward policy tool whose core strength lies in its strong amenability to stakeholder engagement. It does, however, struggle to represent the full

[2] The scenario used is known as the EU Reference Scenario and was derived from the PRIMES model as in chapter 3

complexity of the energy system. This chapter aids REmap in this respect by applying a bi-directional soft-linked methodology to refine the results of REmap for the European power sector and explores how best to balance model complexity and operational ease when determining energy policy by using a highly interconnected pan-European dispatch model.

The final chapter, Chapter 7, presents the conclusions of this thesis, and recommendations for future work.

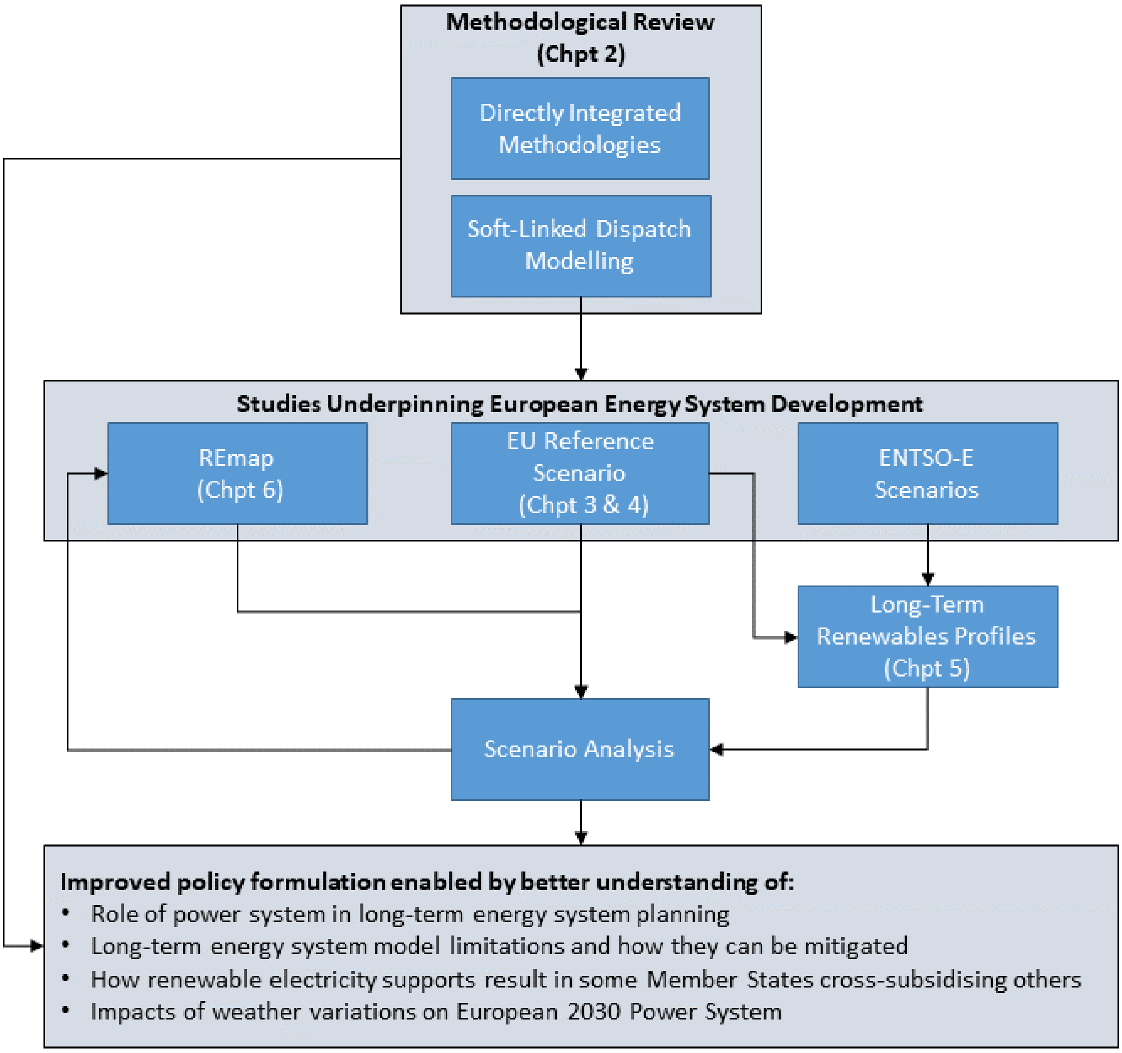

Figure 1.1: Overview of Thesis

1.5. Role of Collaborations

The vast majority of this thesis is my own work. However, the essence of progressive research lies in collaboration that leverages expertise from various disciplines and institutions to produce invaluable insights. To this end, much of this thesis is the result of collaboration between myself and a variety of modelling and renewable energy experts within various universities and institutions. This section serves to clarify my contribution to this thesis and to credit others who have guided and strengthened it. The chapters in this thesis have resulted in five journal papers (4 published and 1 in review), one book chapter (published) and two reports (published). My supervisors Professor Brian Ó Gallachóir and Dr Paul Deane advised on all elements of this thesis.

- **Chapter 2** is based on a published peer-reviewed journal paper for which I was the lead author. This work was carried out in collaboration with Kris Poncelet and Erik Delarue of the Katholieke Universiteit Leuven, Evangelos Panos of the Paul Scherrer Institute and Robert Pietzcker of the Potsdam Institute for Climate Impact Research. All authors developed the concept for the review while I developed the first draft of the manuscript with contributions from Kris Poncelet, Evangelos Panos and Robert Pietzcker and managed the development of the paper. Professor Brian Ó Gallachóir and Dr Paul Deane provided guidance and reviewed drafts. All authors discussed the results and further developed the paper.
- **Chapter 3** is based on a published peer-reviewed journal paper for which I was the lead author. I developed the power system model which was subsequently validated by Dr Paul Deane and wrote this chapter in its entirety. Professor Brian Ó Gallachóir and Dr Paul Deane provided guidance and reviewed drafts.
- **Chapter 4** is based on a published peer-reviewed journal paper for which I was the third author. I developed the power system model underpinning this work which was the subject of a novel ex-post analysis of renewable energy flows by Mr Fiac Gaffney of University College Cork who was lead author. I, Professor Brian Ó Gallachóir and Dr Paul Deane provided guidance and reviewed drafts.
- **Chapter 5** is based on a published peer-reviewed journal paper for which I was the lead author. This work was carried out in collaboration with Dr Stefan Pfenninger of ETH Zurich and Dr Iain Staffell of Imperial College London. I developed the power

system model, wrote the first draft and managed the development of the paper. The power system model was validated by Dr Paul Deane. Dr Stefan Pfenninger and Dr Iain Staffell developed the hourly time series of solar PV and wind generation aggregated to country levels for 30 historical weather years used within the power system model. Professor Brian Ó Gallachóir and Dr Paul Deane provided guidance and reviewed drafts. All authors contributed to designing the research, analysing the results and refining the paper.

- **Chapter 6** is based on a published peer-reviewed journal paper for which I was the lead author. This work was carried out in collaboration with the Innovation and Technology Centre of the International Renewable Energy Agency, specifically Dr Deger Saygin, Dr Asami Miketa, Ms Laura Gutierrez and Dr Dolf Gielen. I wrote this paper in its entirety and carried out all analysis relating to power sector operation while IRENA developed the REmap policy tool used to inform the study. The power system model was validated by Dr Paul Deane. The results of this power sector analysis were published by IRENA and the European Commission in the form a report entitled "Renewable Energy Prospects for the European Union". Professor Brian Ó Gallachóir and Dr Paul Deane provided guidance and reviewed drafts. All authors discussed the results and further developed the paper.

1.6. Thesis Outputs

1.6.1. Journal Papers:

COLLINS, S., DEANE, P., Ó GALLACHÓIR, B., PFENNINGER, S. & STAFFELL, I. 2018. Impacts of Inter-annual Wind and Solar Variations on the European Power System. Joule, 2, 2076-2090.

COLLINS, S., SAYGIN, D., DEANE, J. P., MIKETA, A., GUTIERREZ, L., Ó GALLACHÓIR, B. & GIELEN, D. 2018. Planning the European power sector transformation: The REmap modelling framework and its insights. Energy Strategy Reviews, 22, 147-165.

GAFFNEY, F., DEANE, J. P., **COLLINS, S.** & Ó GALLACHÓIR, B. 2018. Consumption-based approach to RES-E quantification: Insights from a Pan-European case study. Energy Policy, 112, 291-300.

COLLINS, S., DEANE, J. P. & Ó GALLACHÓIR, B. 2017. Adding value to EU energy policy analysis using a multi-model approach with an EU-28 electricity dispatch model. Energy, 130, 433-447.

COLLINS, S., DEANE, J. P., PONCELET, K., PANOS, E., PIETZCKER, R. C., DELARUE, E. & Ó GALLACHÓIR, B. 2017. Integrating short term variations of the power system into integrated energy system models: A methodological review. Renewable and Sustainable Energy Reviews, 76, 839-856.

1.6.2. Policy and Technical Reports:

IRENA & EUROPEAN COMMISSION 2018. Renewable Energy Prospects for the European Union. ISBN: 978-92-9260-007-5

IRENA 2017. Planning for the renewable future: Long-term modelling and tools to expand variable renewable power in emerging economies. ISBN: 978-92-95111-05-9

1.6.3. Book Chapters

DEANE, P., **COLLINS, S.**, Ó GALLACHÓIR, B., EID, C., HARTEL, R., KELES, D. & FICHTNER, W. 2017. Chapter 16 - Impact on Electricity Markets: Merit Order Effect of Renewable Energies. Europe's Energy Transition - Insights for Policy Making. Academic Press. ISBN: 978-0-12-809806-6

1.6.4. Seminar & Workshop Presentations:

COLLINS, S., SAYGIN, D., DEANE, J. P., MIKETA, A., GUTIERREZ, L., Ó GALLACHÓIR, B. & GIELEN, D. Renewable energy prospects for the European Union. Renewables Grid initiative's 5th Future Scenario Exchange Workshop. 11th June 2018, ENTSO-E, Brussels, Belgium.

COLLINS, S., DEANE, P., Ó GALLACHÓIR, B., PFENNINGER, S. & STAFFELL, I. A Multi-Scenario Analysis of European Variable Renewable Power Generation. Proc 36th International Energy Workshop 2017. 12th-14th July 2017, University of Maryland, College Park, Maryland, USA.

COLLINS, S., SAYGIN, D., DEANE, J. P., MIKETA, A., GUTIERREZ, L., Ó GALLACHÓIR, B. & GIELEN, D**.** Transformation of the European Union's power sector to 2030 – Adding value to IRENA's REmap 2030 project using a European Electricity Model. ESRI – UCC- ESRI Energy Research Workshop. 7th June 2016, Dublin, Ireland.

COLLINS, S., SAYGIN, D., DEANE, J. P., MIKETA, A., GUTIERREZ, L., Ó GALLACHÓIR, B. & GIELEN, D. Transformation of the European Union's power sector to 2030 – Adding value to IRENA's REmap 2030 project using a European Electricity Model. Proc 35th International Energy Workshop. 1st-3rd June 2016, Cork, Ireland.

COLLINS, S., DEANE, J. P. & Ó GALLACHÓIR, B. The EU Power System in 2030: curtailment, congestion and prices. ESRI – UCC Energy Research Workshop ESRI. 9th June 2015, Dublin, Ireland.

COLLINS, S., DEANE, J. P. & Ó GALLACHÓIR, B. The EU Power System in 2030: Investigating Electricity Sector Challenges. Proc. International Energy Workshop 2015. 3rd June 2015, Abu Dhabi, United Arab Emirates.

COLLINS, S., DEANE, J. P. & Ó GALLACHÓIR, B. EU Power System in 2030: Investigating electricity sector challenges. ENVIRON 25th Annual Colloquium. 8th-10th April 2015, Sligo, Ireland.

COLLINS, S., DEANE, J. P. & Ó GALLACHÓIR, B. Scrutinizing electricity sector results from PRIMES Energy System model using soft-linking methodology. Proc. 66th Semi-annual IEA ETSAP Workshop. 17th-18th November 2014, Copenhagen, Denmark.

Chapter 2: Integrating Short-Term Variations of the Power System into Integrated Energy System Models: A Methodological Review

2.1. Abstract

It is anticipated that the decarbonisation of the entire energy system will require the introduction of large shares of variable renewable electricity generation into the power system. Long term integrated energy systems models struggle to take account of short term variations in the power system associated with increased variable renewable energy penetration. This can oversimplify the ability of power systems to accommodate variable renewables and result in mistaken signals regarding the levels of flexibility required in power systems. Capturing power system impacts of variability within integrated energy system models is challenging due to temporal and technical simplifying assumptions needed to make such models computationally manageable. This chapter addresses a gap in the literature by reviewing prominent methodologies that have been applied to address this challenge and the advantages & limitations of each. The methods include soft linking between integrated energy systems models and power systems models and improving the temporal and technical representation of power systems within integrated energy systems models. Each methodology covered approaches the integration of short term variations and assesses the flexibility of the system differently. The strengths, limitations, and applicability of these different methodologies are analysed. This review allows users of integrated energy systems models to select a methodology (or combination of methodologies) to suit their needs. In addition, the analysis identifies remaining gaps and shortcomings.[1]

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[1] Published as: COLLINS, S., DEANE, J. P., PONCELET, K., PANOS, E., PIETZCKER, R. C., DELARUE, E. & Ó GALLACHÓIR, B. 2017. Integrating short term variations of the power system into integrated energy system models: A methodological review. Renewable and Sustainable Energy Reviews, 76, 839-856.

2.2. Introduction

The transition to a low-carbon energy system is expected to require the electricity sector to integrate large amounts of variable renewable energy (VRE) (European Climate Foundation, 2010, European Commission, 2011, IEA, 2012b, Luderer et al., 2014). The instantaneous electricity generation by VRE is highly intermittent, location specific and only predictable to a limited extent. A massive penetration of VRE, therefore, has a strong impact on the operation of the power system (Holttinen, 2004, Holttinen et al., 2009, IEA, 2012a, Eurelectric, 2011, Müller et al., 2014, Heptonstall et al., 2017). Capturing the economic and technical challenges related to a large-scale penetration of VRE, therefore, requires modelling the variability in system load and renewable generation, the limited flexibility of thermal units and the spatial smoothing of the variability. This requires models with a high level of temporal, technical and spatial detail.

Long-term planning models have been applied frequently to analyse scenarios for the evolution of the energy system over multiple decades. Due to computational restrictions, the level of temporal, technical and spatial detail in these models is typically low. In contrast, operational power system models focus on the operations of the power system using a high level of detail but do not consider its long-term evolution.

Multiple authors have recently analysed the impact of temporal detail (Poncelet et al., 2016a, Deane et al., 2012, Haydt et al., 2011, Ludig et al., 2011, Pina et al., 2013, Kannan and Turton, 2013, De Sisternes and Webster, 2013), technical detail (Poncelet et al., 2016a, Deane et al., 2012, Palmintier, 2014, Nweke et al., 2012, Welsch et al., 2014, van Stiphout et al., 2016) and spatial detail (Zeyringer et al., 2016, Koltsaklis et al., 2014, Biberacher et al., 2013) employed in long-term planning models. Depending on the representation of integration challenges, low levels of detail can either favour or disfavour VRE: For high penetrations of VRE, If electricity is treated as a homogeneous good or only a low number of averaged time-slices is used, the low level of detail leads to an overestimation of the value of baseload technologies and VRE, while the value of flexible generation technologies with higher generation costs is underestimated (Poncelet et al., 2016a). In contrast, if a model uses rather crude representations of integration challenges such as upper limits on VRE shares or fix backup requirements, the low level of detail can overly restrict the deployment of VRE compared to more detailed representations (Pietzcker et al., 2017). As a result, the cost of achieving ambitious greenhouse gas emission reduction targets can be either significantly under- or overestimated.

Moreover, the importance of capturing critical elements of power system operation for planning a reliable and adequate power system is analysed in (Milligan et al., 1995, Eto, 2011, Undrill, 2010, Ekanayake and Jenkins, 2004, Yingcheng and Nengling, 2011), making clear that a reliable operation of the power system cannot be guaranteed for the scenarios generated by current long-term planning models. As such, Pfenninger et al (Pfenninger et al., 2014) consider 'resolving time and space' to be the main challenge for energy system optimization models. For such long term modelling analyses it is also critical from an operational perspective to capture the current state of play and development of technologies so as to ensure a realistic trajectory of future technology development is considered (Foley et al., 2017, Wang and Li, 2016, Budzianowski and Postawa, 2017, Lefebvre and Tezel, 2017, Shareef et al., 2016).

In view of the challenge of the transition to a less carbon-intensive energy system, it is essential that power system planners model how future power systems (such as those proposed by long term energy system planning models) would be operated (Bell and Gill, 2018, Bukhsh et al., 2018). Bridging the gap between highly-detailed operational power system models and long-term energy system planning models has become an active field of research and numerous methodologies to bridge this gap have recently been developed (Pfenninger et al., 2014, Hidalgo Gonzalez et al., 2015, Poncelet et al., 2016a, IRENA, 2017b).

This chapter presents a review of prominent methodologies developed to better capture the economic and technical challenges related to the integration of VRE in two families of long-term planning models, namely long-term energy system optimization models (ESOMs) usually focusing on country-level (or group of countries, e.g. EU-level) scenarios for the next decades, and integrated assessment models (IAMs), which focus on global long-term scenarios for the full 21st century. The strengths, limitations, and applicability of these different methodologies described in the literature are analysed. This analysis allows users of long-term planning models to select a methodology (or combination of methodologies) to suit their needs. In addition, the analysis exposes the needs for further research.

The remainder of this chapter is organized as follows. First, Section 2.3 identifies the problem space by presenting a comprehensive overview of the different types of models and the level of temporal, technical and spatial detail typically employed in these models. Second, Section 2.4 presents the different methodologies developed in the literature for improved capturing of the economic and technical challenges related to the integration of VRE in planning models. The strengths and limitations of each approach are discussed in detail. Finally, main conclusions are formulated in Section 2.5.

2.3. Overview of Energy Modelling Tools

This section first presents a brief description of the models considered in this chapter, i.e., operational power system models, energy system optimization models and integrated assessment models. Subsequently, the level of temporal, technical and spatial detail typically used in each of these models is discussed.

2.3.1. Operational Power System Models

Operational power system models analyse the operations of a given power system, i.e., investment decisions are not considered. While there are large differences in the focus and applications of operational power system models (Connolly et al., 2010), the focus of this work is on unit commitment and economic dispatch (UCED) models. UCED models determine for every time step within a certain time horizon which units should be online and how much each unit should be generating in order to minimize the cost of supplying a given demand for electricity. Detailed technical constraints, such as the minimal operating level, restricted ramping rates, minimum up and down times, start-up costs and efficiency losses during part-load operation are accounted for on a unit by unit level. Properly accounting for the minimal operating level requires tracking the commitment status of individual units. As such, most current UCED models rely on mixed-integer linear programming (MILP). Due to a large amount of integer variables, solving UCED models can be computationally challenging. The time horizon of UCED models is typically restricted to one day up to one year. This time horizon is disaggregated into different time steps with a resolution in the range of 5 minutes up to one hour. Prominent examples of UCED models used in investment planning studies include PLEXOS (Energy Exemplar, 2018a), LUSYM (Van den Bergh et al., 2016), GTMax (Veselka and Novickas, 2001), ORCED (Hadley, 2008) and EnergyPLAN (Lund, 2015).

While UCED models allow the operation of the power system to be analysed in detail, these models are often limited in terms of network representation to using inter-area transfer constraints rather than more detailed power flow equations and some tools use approximations to constraints such as start-up costs and minimum stable levels to mimic their effect. They also do not typically allow for the (cost-optimal) evolution of the installed generation capacity to be considered. Moreover, the scope of these models is restricted to the power system. Interactions with other energy sectors such as the heating and transport sector are generally modelled by exogenously specifying the demand for electricity.

2.3.2. Long-Term Energy System Planning Models

Long-term energy system planning models are here defined as long term energy system optimisation models (ESOMs). They are used mainly to generate scenarios for the long-term evolution of the energy system. As such, ESOMs compute the investments and operation of the energy system that result in a partial equilibrium of the energy system, i.e., ESOMs simultaneously compute the production and consumption of different commodities (fuels, materials, energy services) and their prices in such a way that at the computed price, production exactly equals consumption. This equilibrium is referred to as a partial equilibrium since the scope of ESOMs is restricted to the energy system (comprising the power sector, transport sector, heating sector, etc.), being merely a part of the overall economic system. To compute this partial equilibrium, ESOMs rely on the fact that this equilibrium is established when the total surplus is maximized (or when total cost is minimized in case of an inflexible demand). Optimization techniques, such as linear programming, are applied to retrieve the investments, production and consumption patterns as well as trade flows yielding a maximal surplus. In contrast to some of the IAMs discussed below, partial equilibrium models are bottom-up models, meaning that each specific sector is composed of multiple explicitly defined technologies which are interlinked by their input and output commodities. Regarding the geographical scope, ESOMs are generally applied to countries or regions, but can also be applied on a city level. The time horizon spanned is generally multiple decades. The main strength of ESOMs is that these models provide a comprehensive description of possible scenarios for the transition of the energy system by considering the inter-temporal, inter-regional and inter-sectoral relationships. A limitation of ESOMs that are applied to only one country is that they ignore the potential benefit of international cooperation for the integration of VRE via expanded transmission grids. Well-known examples of ESOMS are MARKAL/TIMES(Loulou et al., 2005), MESSAGE (IAEA, 2016) and REMIX (Scholz et al., 2016).

2.3.3. Integrated Assessment Models (IAMs)

IAMs and ESOMs share many characteristics and can consist of the same modelling frameworks[2]. The main difference is their aim and scope: ESOMs typically focus on near-term energy system transformations in individual countries or regions, whereas IAMs complement socio-economic modelling with natural sciences to analyse long-term interdisciplinary questions, typically of a global scope, such as assessing policies to mitigate climate change (Moss et al., 2010, Clarke et al., 2014). To address these questions, IAMs need to represent not only the different energy demand sectors such as transport, residential, and industrial energy use, but also topics like economic growth, resource availability, and land-use-related emissions. These differences in temporal, spatial and topical coverage imply that IAMs require higher temporal and geographical aggregation compared to ESOMs for three key reasons. The first is due to the sheer volume and availability of data that would be required in order to have more detailed representation which would be challenging both to attain and manage. The second is in order to keep the computational complexity at a manageable level which can become prohibitive while analysing even a narrow range of scenarios or model sensitivities. The third stems from the challenges that would be encountered when interpreting the results from highly resolved and complicated IAMs where the interactions of a wide range of constraints can be difficult to interpret.

IAMs come in a variety of types: some IAMs like MESSAGE (Messner and Strubegger, 1995), TIAM (ETSAP, 2016, UCL, 2016), POLES (Kitous, 2006), IMAGE (Stehfest et al., 2014) or GCAM (JGCRI, 2018) originate from a bottom-up approach with relatively high

[2] The IAMs ETSAP-TIAM and TIAM-UCL use the TIMES modelling framework, while IIASA's MESSAGE IAM model is built on a MESSAGE modelling framework with additional non-energy sector modules. MESSAGE modelling framework is distributed by the IAEA for national and regional planning purposes. (ETSAP, 2016, UCL, 2016, Messner and Schrattenholzer, 2000)

technological detail, others like AIM/CGE (Fujimori et al., 2012), MERGE (Manne and Richels, 2005), or EPPA (Paltsev et al., 2005) came from a more top-down approach with stronger focus on economic interactions and less on technological detail. In the last decades, most of these models have evolved to become more hybrid in their approach, merging technology detail with macro-economic feedbacks, a feature also found in more recently developed models like WITCH (Bosetti et al., 2007) or REMIND (Luderer et al., 2015).

To offset the low temporal detail and still represent the variability of load and VRE, most IAMs have introduced additional equations and constraints that try to mimic the effect of variability in a stylized way. Examples include implementing hard upper bounds on VRE shares, using inflexible substitution functions, requiring a fixed amount of backup per unit of VRE capacity, adding integration cost mark-ups, or implementing peak capacity equations. (Luderer et al., 2014, Sullivan et al., 2013, De Boer and Van Vuuren, 2016, Carrara and Marangoni, 2017, Pietzcker et al., 2017)

2.3.4. Overview of Model Simplifications

This section describes the main model simplifications which are made in ESOMs and IAMs in terms of the level of temporal, spatial and technical detail used to describe the electric energy system. These simplifications are in contrast with the high resolution modelling of operational power system models that are of a narrower scope. Insufficient temporal, technical or spatial representation can provide incorrect signals regarding the potential and value of different technologies leading to an under- or overestimation[3] of the effort required to transition to an energy system with high proportions of renewable power generation.

Different modelling tools employ different levels of temporal, technical and spatial detail. An overview of the level of detail typically employed in each of these models is presented in Figure 2.1, these are further discussed in the sections 2.3.4.1, 2.3.4.2 and 2.3.4.3.

[3] In IAMs and ESOMs that represent VRE integration challenges in a stylized way, the lack of detail can lead to an overestimation of the effort if the representations are overly restrictive, e.g. by being parameterized based on local time series data that does not represent the potential pooling effect of grid expansion (Pietzcker et al., 2017)

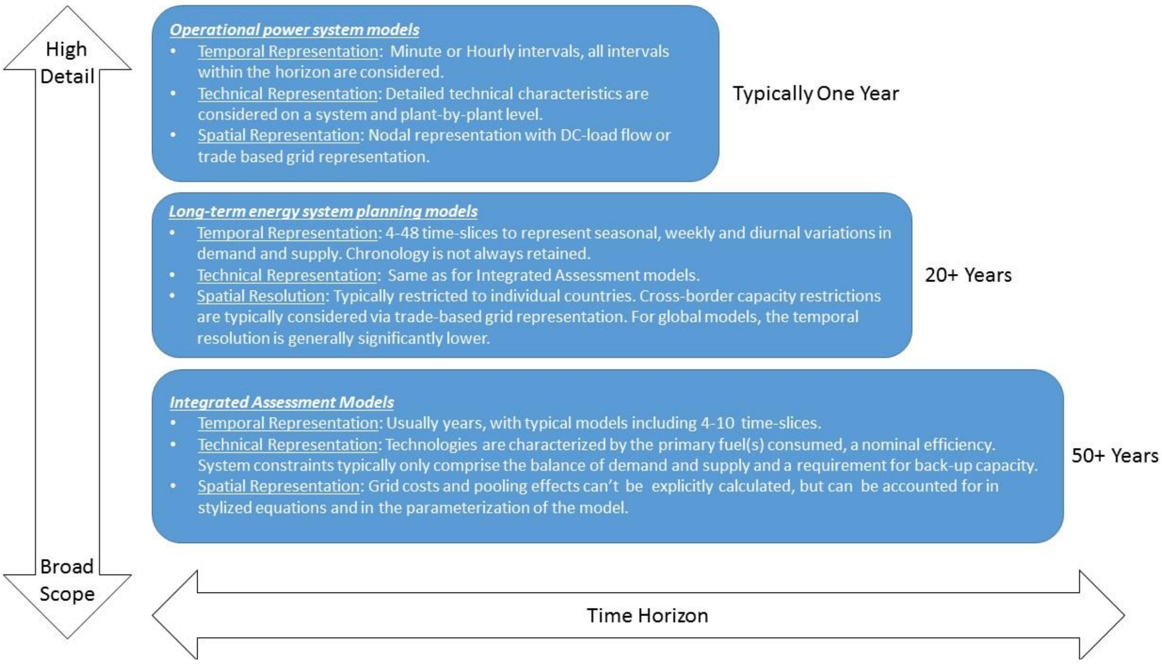

Figure 2.1: Comparison of the level of detail of the model types considered in this analysis

2.3.4.1. Temporal Representation

In ESOMs, the considered time horizon is divided into a number of multi-year periods. Each of these periods is represented by a single year, the so-called milestone year. This milestone year is in turn subdivided into a number of so-called time-slices which represent seasonal, weekly and/or diurnal variations in demand and supply. In most ESOMs, the number of time-slices used and their definition can be determined freely by the user. However, the number of time-slices used typically lies in the range 4-48. Whether or not chronology is retained depends on how the time-slices are defined. A frequently occurring time-slice division uses 12 time-slices to distinguish between day, night and peak hours for four seasons. Examples of models using this time-slice division are the Irish TIMES model (Chiodi, 2014) and the JRC-EU-TIMES model (Gago et al., 2013). Recently, multiple authors have investigated the impact of the stylized temporal representation and have experimented with different ways of creating time-slice divisions by increasing the number of time-slices and/or changing the way these time-slices are defined. A detailed discussion of the impact of the stylized temporal representation in ESOMs and different approaches for setting up the time-slice division can be found in Section 2.4.2.1.

Due to the large scope of IAMs, the level of temporal detail employed in these models is usually lower than in most ESOMs, i.e., the temporal resolution is generally one or several years, although some models like TIMER have as much as 10 time-slices per year. As aforementioned in section 2.3.4, many IAMs represent the effect of temporal variability in a stylized fashion, for these stylized representations, an accurate parameterization is of fundamental importance due to its impact on results. In (Pietzcker et al., 2017) it is found that many of the older parameterizations overly restrict the deployment of VRE compared to newer representations based on better data and more detailed bottom-up analysis. One advanced methodology for representing a number of variability effects in an aggregated way will be discussed in Section 2.4.2.2.

2.3.4.2. Technical Representation

In contrast to UCED models, ESOMs operate on a technology-type level and do not consider the operation of individual units. Hence, their load-following constraints and cycling costs are generally not explicitly accounted for (Poncelet et al., 2016a). Moreover, as modelling detailed load-following constraints such as ramping rate restrictions requires chronological data at a sufficiently high resolution, the possibilities to integrate technical constraints are dependent on the temporal representation, i.e., the time-slice division (Poncelet et al., 2016a). Hence, from a technology perspective, the technological detail is typically restricted to the specification of the efficiency and availability of different generation technologies, while flexibility restrictions are generally not accounted for.

Detailed technical constraints are not considered in IAMs. Similar to the level of temporal detail, additional constraints and parametrizations are used to account for the impact of technical constraints in a stylized fashion. This is also true in the case of ESOMs where technical details are often represented in a stylized way. Such as nuclear plants which are frequently defined on the seasonal time slice level.

2.3.4.3. Spatial Representation

The spatial scope and resolution are important to analyse trade flows and capture the impact of network-related constraints between regions. Both in ESOMs and IAMs, a set of regions is considered, rather than a more detailed nodal level. While this is often also the case for UCED models, the use of a more aggregate regional representation is not required for these models due to their narrower focus. Hence, ESOMs and IAMs are currently not capable of accurately reflecting the impact of transmission network constraints and can encounter challenges in representing the distributed nature of VRE generation.

In ESOMs, the modelling of transmission networks is generally restricted to incorporating the limited capacities of cross-border transmission lines. In addition, the grid representation is typically trade-based where the models themselves function as transport models with electricity flowing as a commodity from supply to demand without representation of power system dynamics and there is no difference between how AC and DC lines are represented. . This is also common in UCED models but more detailed DC load flow grid representation is used in some UCED models such as (Van den Bergh et al., 2016) and it is not strictly a limitation UCED variety models themselves.

Given the regional nature of ESOMs and IAMs, typically without low level nodal disaggregation, the benefits associated with spatial smoothing of VRE generation are challenging to account for. This becomes increasingly important with an increasing penetration of VRE because the correlation between the output of power at different renewable generation sites and from different renewable resources can strongly impact the overall variability and uncertainty of the residual load (Luderer et al., 2015).

2.4. State of the Art Methodologies

This section describes different methodologies that aim to better capture the economic and technical challenges related to the integration of VRE. The methodologies described can be classified into two categories: direct integration and soft-linking model coupling methodologies. Fundamental differences between these categories of methodologies exist. The direct integration methodologies aim to improve the representation of VRE and their impact on the power system by directly improving the temporal, technical and/or spatial representation in the ESOM/IAM, or by introducing additional equations that mimic the effects of higher temporal, technical or spatial detail. In contrast, soft-linking methodologies recognize the limitations of using a single all-encompassing model. In these methodologies, a soft-link between the ESOM/IAM, having a limited level of temporal and technical detail, and a dedicated UCED model is established.

The following sections present an overview of the applications of these different methodologies as well as their respective strengths and limitations. First, Section 2.4.1 describes the soft-linking methodologies for ESOMs and IAMs. Next, Section 2.4.2 and 2.4.3 present direct integration methodologies for ESOMs and IAMs respectively.

2.4.1. Soft-Linking ESOMs/IAMs to an Operational Power System Model

In this methodology, the power system as derived by an ESOM/IAM is used as input for an operational power systems model (i.e., UCED model), which re-computes the operations of this power system using a high level of temporal and technical detail. By analysing the power sector results from the ESOM/IAM in greater temporal and technical detail using the UCED model, this methodology aims to gain additional insights with regard to the operation of the resulting power system. More specifically, it allows more accurate calculations of the expected operational cost, the expected generation mix and corresponding greenhouse gas emissions, the need for curtailment of renewable energy and the reliability of the power system. In addition, the role that different generation technologies play in providing the flexibility required to balance demand and supply can be analysed (Deane et al., 2012).

The main methodological difference in different soft-linking methodologies described in the literature are found in the way the information provided by the UCED model is used. In this regard, we can distinguish between uni-directional and bi-directional soft-linking methodologies. In uni-directional soft-linking methodologies, there is no direct link from the UCED model to the ESOM/IAM, i.e., the UCED model is only used to provide additional information and as a check on the results provided by the ESOM/IAM. In bi-directional soft-linking methodologies, the information provided by the UCED model is used to systematically adapt certain parameters and/or add certain constraints in the ESOM/IAM. In an iterative procedure, both models are executed repeatedly until convergence between both models is obtained. Bi-directional soft-linking poses additional difficulties but allows to move closer to the globally optimal solution, i.e., the solution that would have been found if the ESOM/IAM could have been solved with high levels of temporal, technical and spatial detail. Hence, the added value of using a bi-directional soft-linking methodology increases as the results provided by the ESOM/IAM and the UCED diverge more strongly (and the solution of the ESOM/IAM drifts away from the global optimal solution). As shown by multiple authors, the divergence between the results provided by ESOMs and UCED models increases with the penetration of VRE in the power system (Kannan and Turton, 2013, Haydt et al., 2011, Poncelet et al., 2016a, van Stiphout et al., 2016), which indicates that bi-directional soft-linking methodologies are especially useful for modelling scenarios with very high shares of VRE.

It is important to note that in order to employ the soft-linking methodology correctly, both the ESOM/IAM and the UCED models should share certain common inputs, in particular, the time series for the electricity demand and renewable generation to ensure comparable model results. An example of a detailed step-by-step uni-directional soft-linking methodology is presented in (Deane et al., 2012):

1. Define the scenario and time horizon of the analysis and execute the ESOM/IAM.
2. For a specific year of interest, extract the electricity generation portfolio, fuel prices and carbon prices from the ESOM/IAM and populate the UCED model with this data. Include additional technical parameters, such as minimum stable generation levels, ramp rates, start costs, failure rates and maintenance rates, in the UCED model.
3. Convert the annual electricity demand time series from the ESOM/IAM to a chronological time series with hourly or lower resolution. This is done through taking a historical demand time series and scaling using quadratic optimisation so as the annual demand and peak demand for electricity are equal to the demand from the ESOM/IAM. In addition, use high-resolution time series for VRE electricity generation based on the installed capacity and available historical generation time series or resource data (e.g., wind speed or solar irradiance data) for each region.
4. Initially run the UCED model for the target year using the high-resolution time series without any additional technical constraints such as minimum stable generation, ramp rates or start costs to demonstrate the impact of increased temporal detail within the model.
5. As next step, run the model with increasing levels of technical detail in order to determine the impacts of these technical constraints on the model results.
6. Contrast results between the models, identify differences and scrutinise the reliability and flexibility of the power system. Analyse the role that different generation technologies play in system operation.
7. Determine the implications of low production years for VRE modes of generation, such as wind and solar, on the reliability of the derived portfolio from the energy system model by running the power systems model with a number of different years of production profiles.

This uni-directional soft-linking methodology is illustrated in Figure 2.2 for an example where a TIMES ESOM with the target year of 2030 is soft-linked to the PLEXOS UCED model to analyse the results for the year 2020.

For a bi-directional soft-link, an additional step is required in the methodology:

8. Use the insights gained from the results comparison to introduce constraints into the ESOM/IAM model to take account of the power system operation characteristics that are not readily captured within the ESOM/IAM.

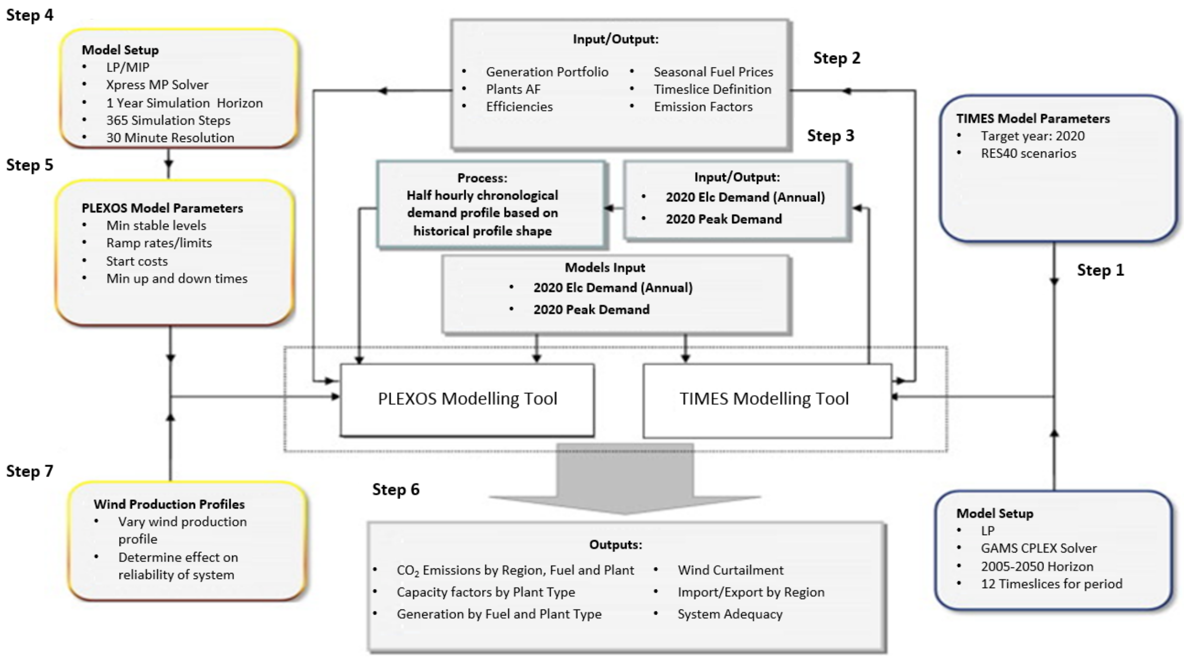

Figure 2.2: Flow chart of soft-linking methodology. (Deane et al., 2012)

The main difficulty with bi-directional soft-linking is specifying the adaptation of parameters and/or constraints of the ESOM/IAM in response to the results provided by the UCED model in such a way that both models converge to a globally optimal solution. In (Rosen et al., 2007), a bi-directional soft-link is used, but no information is provided on the details of the feedback from the UCED model to the ESOM. As stated in (Welsch et al., 2015), this feedback mechanism is often ignored. In (Pina et al., 2013), maximum investment in wind generation capacity is restricted if annual curtailment of wind generation exceeds 10% of the expected annual wind generation. This feedback loop thus only directly impacts wind generation capacities. Sub-optimalities in the thermal generation fleet resulting from using a low level of temporal and technical detail are not corrected for. Hence, while this approach might result in a solution closer to the global optimum, this cannot be guaranteed. Further research is required to investigate the convergence in bi-directional soft-linking of ESOMs/IAMs and UCED models.

Soft-linking methodologies have recently been applied frequently to ESOMs. A number of studies used a uni-directional soft-link to analyse the impact of the limited level of temporal and technical detail typically used in ESOMs (Welsch et al., 2014, Deane et al., 2015b, Poncelet et al., 2016a). In addition, this approach has been applied in a number of studies to scrutinise energy system model results (Deane et al., 2015a, Brouwer et al., 2015, Rosen et al., 2007). In (Brouwer et al., 2015), a soft-link between a MARKAL model of the Netherlands and REPOWERS is used to assess flexibility sufficiency, quantify the impact of part-load efficiency losses and assess the profitability of power plants in scenarios for the evolution of the Dutch power system. A similar analysis is performed in (Deane et al., 2015a), where a soft-link between the ESOM MONET and PLEXOS is used to scrutinise the evolution of the Italian power system in different scenarios, with a focus on power system security. Rosen et al. (Rosen et al., 2007) use a bi-directional soft link between the PERSEUS-CERT model and the AEOLIUS model to obtain more accurate estimates of displacement of intermediate-load and base-load plants by wind generation and the resulting impact on greenhouse gas emission reduction in Germany.

Recently, Zeyringer et al. (Zeyringer et al., 2016) used a soft-link between an ESOM and a power system model with a high level of temporal and geographical detail. In contrast to the soft-linking approaches between ESOMs and UCED models, the power system model endogenously optimizes the location of the VRE and the need for conventional dispatchable technologies and storage technologies. This type of soft-link has the benefit that it allows the provision of a solution which is closer to the global optimal solution without requiring a bi-directional soft-link.

While the soft-linking methodology can theoretically be applied to IAMs as well, the increased complexity due to a large number of regions and long time horizon covered make this a challenging exercise, as each power sector in each region and time step needs to be checked by a power system model run. Thus, the only examples we know of are a country-level IAM, namely the US-REGEN model that soft-links a CGE model of the United States to a bottom-up unit commitment and dispatch model (Young et al., 2015), and a study with the global POLES model that soft-linked only the EU countries to a dispatch model based on 12 representative days (Després et al., 2016).

2.4.1.1. Advantages and Limitations

The main advantage of soft-linking ESOMs/IAMs to UCED models is that it provides very detailed information on the operation of the power system. As such, this approach not only provides accurate estimates of the cost, fuel consumption and GHG emissions of operating the power system but also allows to analyse power system reliability, the need and provision of flexibility and the role specific generation technologies play in balancing demand and supply. As such, this methodology provides a robust check on the results provided by the ESOM/IAM. Using a bi-directional soft-link provides the additional advantage of improving the overall solution of the ESOM/IAM without requiring the computational resources needed to solve one ESOM/IAM with very high levels of temporal, technical and operational detail.

A first disadvantage is that two separate models need to be constructed and maintained, requiring additional resources and expertise. An additional disadvantage is that uni-directional soft-linking methodologies do not impact the investment decisions of the ESOM/IAM, and thus do not provide a globally optimal solution. In contrast, investment decisions can be altered in bi-directional soft-linking methodologies. However, the feedback from the UCED model to the ESOM/IAM model is currently based on the skill and judgment of the modeller given the undertaking at hand. A limitation of this approach is that it is not a directly integrated approach, which makes it a sub-optimal approach because insights gained from the power system model have to be exogenously forced within the energy system model. More research is needed to investigate the convergence and the optimality of results provided by bi-directional soft-linking methodologies.

2.4.2. Direct Integration Methodologies for ESOMs

2.4.2.1. Improving the Temporal Representation

As discussed in Section 2.3.4, ESOMs typically have a stylized temporal representation, in which intra-annual variations in demand and supply are represented by a low number of so-called time-slices. Haydt et al in (Haydt et al., 2011) distinguish between two methods of balancing supply and demand in ESOMs.

A first method is the so-called 'integral method', in which typically 5-10 time-slices are used to distinguish between different load levels occurring throughout the year. In this method, each time slice thus represents an average load level during a certain fraction of the year (as shown in Figure 2.3 where each bar represents a time-slice). In this method, all chronological information is lost as different load levels can occur at different moments in time. Due to the loss of chronology, average VRE capacity factors are used. In addition, the dynamics of variations in demand and supply are not captured. As a result, the value of storage systems and other flexibility options cannot be determined.

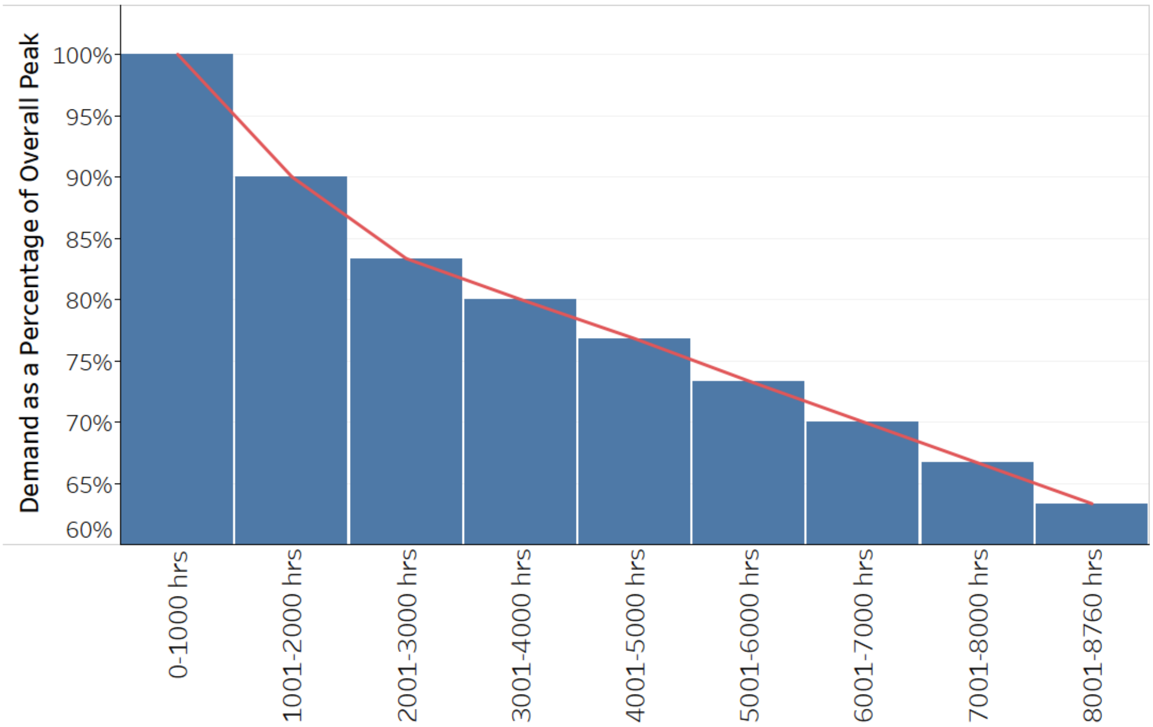

Figure 2.3: Example of a time-slice division used in energy system optimization models using the "integral" method where each bar represents a time-slice and the red line is illustrative of the load duration curve.

A second method is the so-called 'semi-dynamic method' which is based on using a number of typical or representative days. In this 'semi-dynamic method' method, each typical or representative day represents a fraction of the year, e.g., corresponding to (a part of) a season. Each day can, in turn, be disaggregated into a number of diurnal time-slices (as shown in Figure 2.4). Due to the fact that chronology is retained within each day, the value of storage systems and other sources of flexibility can be endogenously determined. An example of a time-slice division disaggregating a year into seasonal, daily and diurnal time-slices is presented in Figure 2.4 (Loulou et al., 2005). At the lower level, each time-slice is defined by a fraction of the year it represents and a fixed value for the load and VRE capacity factors (Poncelet et al., 2016a).

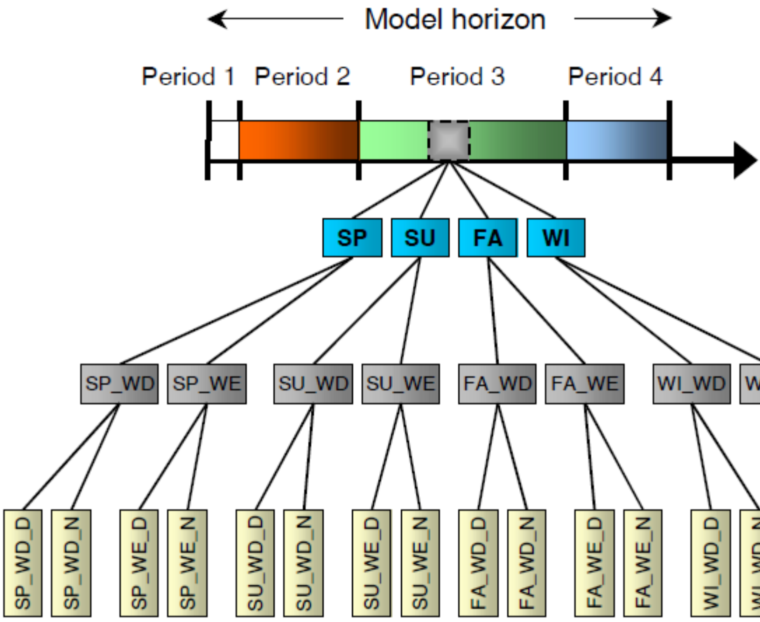

Figure 2.4: Example of a time-slice division used in energy system optimization models using the "semi-dynamic" method (Loulou et al., 2005)

Recent literature has shown that the approach used to assign values for the load and VRE capacity factors to every time-slice can strongly impact the results (Poncelet et al., 2016a). The approach traditionally applied is to take the average value of that part of the time series that corresponds to the definition of the time-slice (e.g., the average solar capacity factor during summer days). A second approach only uses the data of a selected number of representative historical periods. These periods can in principle be hours (e.g., (Young et al., 2015)), days (e.g., (Nahmmacher et al., 2014a, Poncelet et al., 2016b)), or weeks (e.g., (De Sisternes and Webster, 2013)). However, most commonly, a set of days is used.

In literature, the terms 'representative days', 'typical days' and 'type-days' are used interchangeably. All these terms are used to refer to both time-slice divisions based on using the data of a small selection of historical days, and to time slice divisions using the traditional approach where data averaging is used to obtain a number of typical days. In this text, we will refer to 'typical days' as days formed by averaging data, whereas we refer to 'representative days' as specific historical days.

In the majority of ESOMs, the semi-dynamic method of balancing demand and supply is used where data averaging is used to create a number of typical days. In this regard, a frequently occurring time-slice division uses 12 time-slices to distinguish between day, night and peak hours for four seasons, i.e., a single typical day is created per seasons which is further disaggregated into 3 diurnal time-slices. Examples of models using this time-slice division are the Irish TIMES model (Chiodi, 2014) and the JRC-EU-TIMES model (Gago et al., 2013).

The impact of such a commonly applied, stylized, temporal representation on the model results has been investigated in great detail by multiple authors (Kannan and Turton, 2013, Deane et al., 2012, Ludig et al., 2011, Haydt et al., 2011, Pina et al., 2011, De Sisternes and Webster, 2013, Poncelet et al., 2016a). The results of their analyses have shown that using time-slices based on simple averaging leads to an underestimation of the variability of variable RES. This underestimation of the variability follows from the fact that when typical days are derived from a strictly temporal pattern (each time-slice represents a certain season, week, part of the day) , the capacity factor assigned to each time-slice results from taking the average over each instance of the pattern. As VRE and specifically wind generation does usually not follow the same temporal pattern, the averaging thus smooths periods of very high and very low VRE generation. (Ludig et al., 2011, De Sisternes and Webster, 2013, Poncelet et al., 2016a). This, in turn, leads to an overestimation of the potential uptake of variable RES and an overestimation of the potential of baseload technologies while flexible and peak-load technologies are not sufficiently valued (Deane et al., 2015b, Pina et al., 2013). As a result, such a stylized temporal representation is shown to lead to an underestimation of the total system costs. While the impact on model results has shown to be limited to a low penetration of variable RES, it grows with penetrations of variable RES (Poncelet et al., 2016a). In the following, we present four methodologies to directly improve the temporal representation in ESOMs

2.4.2.1.1. Semi-Dynamic Balancing Using Typical Days with Increased Resolution

First, a number of authors have experimented with increasing the temporal resolution (i.e., the number of diurnal time-slices) of the typical days (Kannan and Turton, 2013, Ludig et al., 2011, Haydt et al., 2011, Pina et al., 2011, Poncelet et al., 2016a, Kannan et al., 2015, Kannan and Turton, 2011). Pina et al. (Pina et al., 2011) increase the number of time-slices used in a TIMES model for Sao Miguel (Azores, Portugal) to 288 by considering 4 seasons, 3 types of day per season (weekday, Saturday, Sunday) and 24 hours per day. By varying the number of diurnal time-slices, they show that using an hourly resolution impacts results. More specifically, fewer investments in wind turbines are observed when the resolution is increased. In an analysis of the Swiss power system using the Swiss TIMES electricity model (STEM-E) (Kannan and Turton, 2011), the benefits of a greater temporal resolution are demonstrated by a comparison between the model with 288 time-slices and an aggregated version with 8 time-slices (Kannan et al., 2015). While increasing the temporal resolution is shown to yield some benefits, mainly in capturing the variations in load and solar generation, Ludig et. al. (Ludig et al., 2011) have shown that increasing the resolution of the typical days is not sufficient to grasp the inherent variability of wind power, because wind generation in the studied area (Germany) is little correlated with the time of the day. A more elaborate discussion in this regard can be found in (Poncelet et al., 2016a) where it is shown that it is not merely the temporal resolution which impacts results but also the technical representation of modelling that is itself strongly influenced by the temporal representation.

2.4.2.1.2. Integral Balancing Based on Approximating the Joint Probability Distribution of the Load and VRE Generation

A second methodology is to expand the integral method of balancing demand and supply to slicing the joint probability distribution of residual load and VRE generation. This can be done by not only distinguishing explicitly between different load levels occurring throughout a year but by simultaneously accounting for different levels of VRE generation (Poncelet et al., 2016a, Després et al., 2016, Lehtveer et al., 2016). Following the methodology of the integral method, a year can first be subdivided into different bands of load levels, each representing a certain fraction of the year. These time-slices can be further disaggregated into periods with high and low wind generation and high and low solar generation. The advantage of this approach is that the variability of load and VRE generation and their correlation are accounted for with only a limited number of time-slices. However, the disadvantage of this approach is that the chronology is lost, and the dynamics of the system and the corresponding value of flexibility options, such as storage systems, cannot be represented (Poncelet et al., 2016a). The importance of retaining chronology for the cost-optimal evolution of the South-Australian power system is analysed in (Nweke et al., 2012), where the results of a model with and without chronology were compared. In the presented case, differences in the capacity mix were shown to be significant. The model that retains chronology is shown to invest less in VRE and baseload technologies and more in flexible thermal power plants. However, the total system cost resulting from the capacity expansion plans obtained using the model with and without chronology were shown to be very similar for the presented case. Recently, this improved integral method has been applied to the GET model (Lehtveer et al., 2016).

2.4.2.1.3. Semi-Dynamic Balancing Using Representative Historical Periods

A final methodology is to use the semi-dynamic method with representative historical periods instead of averaged typical days. A schematic of using a set of historical periods in ESOMs is presented in Figure 2.5. From various time series (e.g., load, wind speed, solar irradiance), a number of representative periods $d \in D'$ are selected. Each of these selected periods is given a certain weight w_d, i.e., the number of times this period is assumed to be repeated within a single year. The ESOM aims to minimize the sum of fixed costs and variable costs. While the fixed costs are only dependent on the investment decisions cap_g in different technologies g, the variable costs are dependent on the electricity generated by each of these technologies in every time step $gen_{g,d,t}$. The balance of demand and supply is imposed for every time step t (e.g., hour) of every representative period d. The weights w_d are then used to scale the variable costs incurred during each representative period to an equivalent annual amount. Similarly, the annual electricity generation from different generation technologies g and the corresponding greenhouse gasses can be scaled to equivalent annual amounts. Since only the data of historical periods is used, averaging of load or VRE generation is only needed to reduce the number of diurnal time-slices. As a result, the variability of load levels and VRE generation can be captured. In addition, chronology is maintained. For these reasons, this methodology can capture the short-term dynamic variations in demand and supply, which is crucial to assess the value of and need for short-term storage systems, and to allow modelling the limited flexibility of the generation technologies (e.g., ramping rates, start-up costs). However, a careful selection of a set of representative historical periods is essential for the quality of this methodology. Indeed, not every set of historical periods will provide a good approximation of the joint probability distribution of load and VRE generation levels, as shown in (Poncelet et al., 2016a). Therefore, care should be taken in carefully selecting a representative set of historical periods.

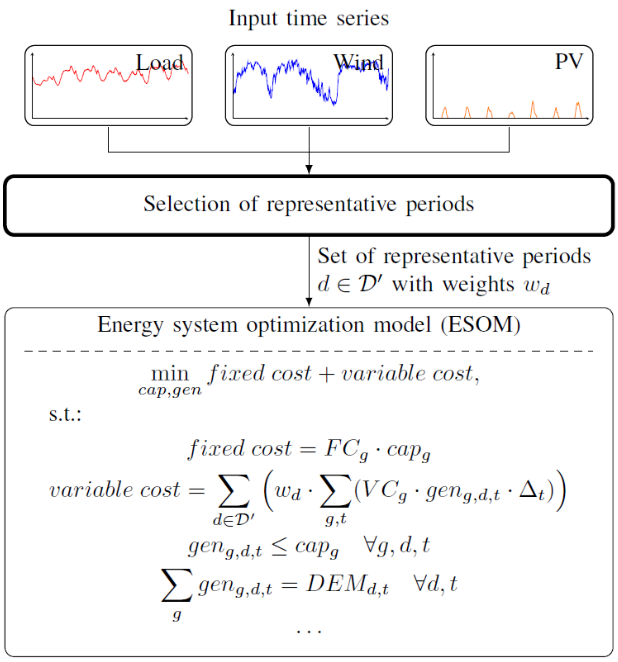

Figure 2.5: Schematic of how a set of representative days can be used in ESOMs (Poncelet et al., 2016b)

To select a representative set of historical periods, multiple approaches can be found in the literature. A comprehensive overview of different approaches, their strengths and limitations can be found in (Poncelet et al., 2016b). Certain approaches rely on simple heuristics (e.g.(Haller et al., 2012, Kirschen et al., 2011, Belderbos and Delarue, 2015, Fripp, 2012, Neuhoff et al., 2008)). More advanced approaches make use of clustering algorithms to cluster days with similar load, wind speed and solar irradiance patterns. Different clustering algorithms, such as Ward's hierarchical clustering algorithm (Nahmmacher et al., 2014a), the k-medoids (ElNozahy et al., 2013), k-means (Fazlollahi et al., 2014, Omran et al., 2010, Nick et al., 2014) and fuzzy C-means algorithm (ElNozahy et al., 2013) have been applied in this regard. Once all days are grouped into a number of clusters, a single representative day is selected from each cluster. The weight assigned to each representative day, i.e., the number of time this representative days is assumed to be repeated within one year, corresponds to the number of days that are grouped into its parent cluster. These clustering algorithms thus have the advantage that the weights of each representative day are determined exogenously. This allows to account for rare events, while common situations can be represented by a low number of days with large weights. Clustering techniques have been applied to select representative periods in the LIMES-EU model (Nahmmacher et al., 2014b), the US-REGEN model (Young et al., 2015) and the POTEnCIA model (Mantzos et al., 2016). Other approaches randomly select numerous potential sets of representative historical periods and use metrics to assess the quality of these sets in order to pick a representative set of historical periods (De Sisternes and Webster, 2013). A fundamental difference with the heuristic approaches discussed above is that the selection is based on the evaluation of the full set of representative periods, whereas in the heuristic approaches, the selection is based on the characteristics of individual historical periods or the similarity between individual historical periods. A final approach makes use of a mixed-integer linear programming (MILP) model to select a set of representative historical days (binary variables) and their weights (linear variables) in order to minimize the errors in approximating the distribution of load and VRE generation time series as well as their correlation (Poncelet et al., 2016b).

Different approaches to select representative days are compared in (Poncelet et al., 2016b). It is shown that by optimizing the selection and weights of the representative days using the MILP model, more accurate results are obtained than the ones obtained through random selection algorithms, clustering algorithms and heuristic approaches. A better selection of representative days allows to increase the accuracy from the ESOM without increasing the computational cost. Particularly for models which are restricted to a low number of time-slices, the added value of a better selection of representative days can be high.

In an application of the LIMES-EU model of the European power system, Nahmmacher et al. (Nahmmacher et al., 2014a) have compared the model results for a varying number of representative days. Their results show that the accuracy of the ESOM increases as more representative days are selected, but the marginal benefit of increasing the number of days rapidly decreases. As a trade-off needs to be made between the computational complexity and the accuracy of the model, they conclude that using 6 representative days is sufficient to obtain a reasonable accuracy: in their presented case, increasing the resolution from 6 to 100 representative days only changes total system costs by 4%. Using a 3-hourly time-resolution, the 6 representative days corresponds to a total of 48 time-slices, which lies in the range of time-slices frequently used in ESOMs.

2.4.2.1.4. Using Stochastic Programming as a Means to Address Modelling Uncertainties

Increasing the temporal representation to capture RES profiles improves the quality of the solution obtained, and by using state-of-the-art methodologies for selecting representative days leads to accurate sampling of solar and wind availability historical profiles and results in investment decisions that incorporate notions of hedging. Yet, these investment decisions are taken with perfect knowledge about the availability of solar and wind energy, while in reality they are made before the uncertainty surrounding this availability is resolved. This decision problem can be accurately modelled with a two-stage stochastic programming (Dantzig, 1955) which can be applied in a similar manner as it has been applied for long-term decisions under uncertainty, e.g. in (Wallace and Fleten, 2003, Usher and Strachan, 2012, Keppo and van der Zwaan, 2012). Thus, the investments in power generation and storage technologies can be made in the first stage, while in the second stage these investment decisions are fixed, the uncertainty about the solar/wind profiles is resolved and recourse actions are taken to find optimal investment decisions. The application of stochastic programming relies on scenario trees, in which each stage corresponds to a resolution time[4] and is characterised by a set of states[5] (Figure 2.6 on the left). Each path from the first node to any last node in the tree is called "scenario". A typical mathematical formulation of a two-stage stochastic programming problem can be found in (Ahmed, 2010).

Recurring uncertainties, such as hydrological and wind/solar conditions, lead to a simplified formulation, because the information about already resolved uncertainties of the past cannot be used for future investment decisions (Loulou and Lehtila, 2007). Thus, the investment decisions variables have a single state in all periods, and only period-specific generation variables are split into the set of states implied by the scenario tree. If the recurring uncertainties can be also considered independent between successive periods[6], then a further simplification can be achieved by taking into account that the impacts these uncertainties are no longer conditional on the state of the previous period. This assumption eliminates the necessity to branch the scenario tree in every modelling time period (Figure 2.6 on the right). Following this approach, the investment decisions are made in the first stage for every modelled time period and come into effect in the second stage of the same

[4] Resolution time is the time when the actual value of the uncertain parameter is revealed.
[5] The states correspond to the different values, together with their corresponding probabilities, that an uncertain parameter has in this particular stage.
[6] This holds for example in the uncertainties related to solar and wind availability.

modelled period, by when the true availability of wind and solar energy is revealed (Seljom and Tomasgard, 2015).

Each node of the second stage in the scenario tree has an operational time structure, defined by a number of timeslices (in Figure 2.6 288 timeslices are defined in each node delineated into 4 seasons and 3 typical days of hourly resolution). Solar and wind profiles are mapped to these timeslices either by random sampling or by using representative days (see section 2.4.2.1.3). All nodes belonging to the same scenario have exactly the same wind and solar profiles. However, across different scenarios the solar and wind profiles are different and they are associated with a probability of occurrence[7]. The total number of timeslices in a modelling year is the product of scenarios with the number of timeslices in each node[8].

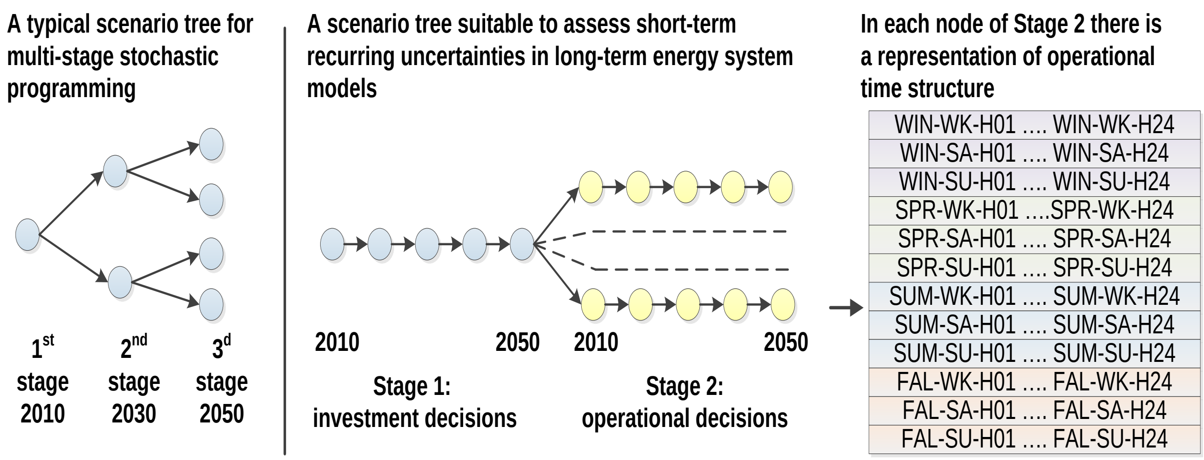

Figure 2.6: Description of scenario trees: a typical multi-stage scenario tree (left) and a modified scenario tree for short-term recurring uncertainties (right). This figure is an adapted version of Figures 4 and 5 in (Seljom and Tomasgard, 2015) and Figure 4 in the appendix of (Loulou and Lehtila, 2007)

The derived scenario tree must be stable in order to ensure that the solution obtained does not depend on the representation of the scenario tree but on the underlying data set. This requires a large number of scenarios to be initially created by using appropriate scenario tree generation algorithms (Høyland and Wallace, 2001, Kaut and Wallace, 2003) and then to employ scenario reduction techniques (Gröwe-Kuska et al., 2003) to improve the computational time. For example, iterative random sampling of actual historical days can

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[7] This also implies that there is the flexibility to use state-of-the-art methodologies for selecting representative days for each scenario in the scenario tree and then each scenario to correspond to wind and solar profiles from different historical years.
[8] For example if we assume 90 scenarios with 288 timeslices in each node, then the total number of timeslices in a year is 25920; this implies that a typical operational hour in a year is delineated into several instances with respect to the values of the underlying random variables.

be employed[9] (Seljom and Tomasgard, 2015) in order to create a large number of different scenario trees and then to select the one that displays the minimum deviation in the first four moments[10] with the historical data. Alternatively one may consider the application of state-of-the-art methodologies for selecting representative days (section 2.4.2.1.3) to generate different scenarios that correspond for example to different historical years.

Among the advantages of using stochastic programming are: a) the evaluation of hedging strategies; b) the endogenous requirements of back-up capacity; c) the possibility to measure the expected system cost disregarding uncertainty through the metric of the Value of Stochastic Solution[11] (VSS) (Birge, 1982, van der Weijde and Hobbs, 2012), and; d) the provision of insights regarding the additional cost for providing back-up capacity and storage options[12] (and also for diversifying the electricity generation mix) through other metrics (Birge, 1982) and especially through the Expected Value of Perfect Information[13] (EVPI) .

In concluding this section, it should be noted that the approach presented in section 2.4.2.1.3 can be used in stochastic programming to improve the sampling of the underlying distributions of wind and solar power. This synergy occurs when constructing a specific scenario in the scenario tree. In fact, the similarity of stochastic programming and the approach presented in section 2.4.2.1.3 is that both are sampling the distributions of solar and wind availability with high accuracy. The difference lies that in deterministic approaches the investments are made with perfect knowledge about the solar and wind availability, while in stochastic programming this information is unknown at the time of the investment.

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[9] For example S days are randomly selected to form the nodes of a scenario tree and by repeating this sampling N times, N different scenario trees are constructed from which the one that better reflects the underlying probability distributions of the random variables is selected.

[10] The first four moments of a probability distribution include: mean, variance, skewness and kurtosis.

[11] The VSS is defined as the difference between the expected optimal objective function value of the stochastic model with fixed investment decisions as they calculated by the deterministic model and the value of the objective function from the stochastic model.

[12] This can be also viewed as the support for enabling investment in flexible technologies (e.g. capacity payments) and in storage options to cope with the intermittency of solar and wind power.

[13] The EVPI is the difference between the average performance with perfect information and the optimal stochastic solution. The EVPI can be also used as a proxy of how much are willing to pay to eliminate uncertainty.

2.4.2.1.5. Advantages and Limitations

Four distinct methodologies have been put forward in literature. The first methodology to improve the temporal representation in ESOMs that has been described above is to increase the resolution of the typical days. Due to the fact that typical days are created by averaging data of multiple days, the variability of VRE capacity factors is underestimated, even if the resolution is increased.

A second methodology is to expand the integral method of balancing demand and supply to approximate the joint probability distribution of load and VRE generation. The first advantage of this approach is that the distribution of the load and VRE generation can be captured relatively well in a limited number of time-slices. Second, the correlation between different time series is accounted for. This way, the residual load duration curve will be approximated well for varying shares of VRE. Finally, implementing this approach requires a minimal effort. However, the main drawback of this approach is that chronology is lost, making it impossible to endogenously incorporate technical dynamic constraints and to determine the value of storage and other flexibility options.

Another methodology is to use the data of a limited number of representative historical periods. The advantage of this approach is that both the distribution of the load and VRE generation can be captured while at the same time retaining the chronology. The main disadvantage of this approach is that the quality of this approach is strongly dependent on a good selection of a representative set of historical periods. A proper selection of a representative set of historical periods, therefore, requires the implementation of specific selection algorithms or optimization routines.

The stochastic programming based methodology has benefits in that it makes the need for back-up capacity endogenous, allows for the hedging of flexible generation and allows for detailed quantification of uncertainty. Limitations of the approach are its dependence on the representation of uncertainty parameters which are specific and influential in model results and that the approach adds to the computation cost required for the model run[14]

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[14] Solving a recourse problem is generally difficult because it requires the evaluation of the expected costs of the second stage. This implies a high-dimensional numerical integration on the solutions to the individual mathematical programs of the second stage. However, when the random data are discreetly distributed then

All these methodologies aim to improve the temporal representation such that the operations of the power system and the resulting cost, fuel consumption, GHG emissions, and reliability are better approximated. As such, by improving the temporal representation directly in the ESOM, the solution will become closer to the global optimal solution. While these approaches can be used to provide a more adequate and reliable power system, using either of these approaches is not sufficient to guarantee a reliable system. To this end, an even higher level of temporal detail and the inclusion of technical constraints would be required, as is the case in the soft-linking methodology. Moreover, all four methodologies highlighted above require using a somewhat higher number of time-slices than most ESOMs use at this moment.

2.4.2.2. Improving the Technical Representation

As discussed in Section 2.3.4, ESOMs typically do not consider individual power plants and the corresponding load-following constraints. This leads to an underestimation of total system cost and the need for flexibility providers (Poncelet et al., 2016a, Deane et al., 2012, Palmintier and Webster, 2011, Welsch et al., 2014, van Stiphout et al., 2016). Although the impact of reduced technical detail is significant, for high penetration levels of VRE, it was shown that the impact of the stylized temporal representation typically used in ESOMs is higher than the impact of the level of technical detail (Palmintier and Webster, 2011, Deane et al., 2012).

2.4.2.2.1. Stylized Integration of Operational Constraints

A detailed implementation of the technical constraints which limit the flexibility of dispatchable power plants requires considering individual units and use of chronological data with a sufficiently high resolution (Poncelet et al., 2016a). As using such a high level of detail would make ESOMs intractable, more stylized representations of technical constraints are frequently implemented. As such, these stylized constraints do not directly represent the physical processes, but rather aim to mimic the impact of these physical constraints on the generation scheduling. Therefore, calibration of such constraints using more detailed models is required. Moreover, as this calibration depends on a lot of

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the stochastic problem can be written as a deterministic equivalent problem, in which the expectations are included as finite sums and each constraint is duplicated for each realisation of the random variables.

parameters, care is needed in transferring these constraints to applications of different power systems.

There are ample examples of such stylized representations of technical constraints. A first example can be found in (De Jonghe et al., 2011), where a must-run level and ramping rates are specified at a technology level to represent all technical constraints and costs related to load-following. For this reason, they state that the applied ramping rates should not be directly compared to the ramping rates of individual power plants. The European Electricity Market Model (EMMA) also does not consider individual plants (and corresponding integer variables). To mimic the behaviour of plant operators with respect to start-ups, generation costs of certain technologies are lowered such that these plants would not shut down if electricity prices would briefly drop below the actual generation cost. To prevent distorting total costs, the fixed costs of these technologies are increased (Hirth, 2013). Although this approach can to some extent mimic the effect of start-up costs, it does not allow modelling of hard physical constraints such as maximal ramping rates and minimum up and down times. Similarly, in the Regional Energy Deployment System (ReEDS), a cost penalty is attached to ramping and a minimum loading constraints prevents certain technologies from excessive cycling (Short et al., 2011). One specific, very popular, though highly stylized, method frequently used is to differentiate between inflexible (baseload) plants and flexible (peakload) plants by defining them at a different time slice levels. Typically, nuclear plants are defined at the annual level, meaning that their output is assumed to be fixed at one level for the entire year. Coal plants are often assumed to be slightly more flexible so that they can change their output between different seasonal time slices, while more flexible technologies are allowed to adapt power output freely. Although the exact implementation can differ, this method is amongst others used in (Gago et al., 2013, Devogelaer et al., 2012, Kannan and Turton, 2013, Fripp, 2012). Recent developments of modelling frameworks for ESOMs enable stylized capture of the Unit Commitment and Economic Dispatch (with representation of characteristics such as ramping, minimum stable operation levels, minimum up and down times, start up and shutdown times and partial load efficiencies), such as for the TIMES ESOM in (Panos and Lehtilä, 2016).

2.4.2.2.2. Modelling Ancillary Services Markets in Long-Term Energy System Models

Ancillary services (or operating reserves) are provided by power plants in order to balance the power system in the case of forecast errors in supply and demand that result in frequency deviations. Three types of operating reserves are typically distinguished with different activation times (Rebours and Kirschen, 2005): primary, secondary and tertiary. However, there has been a move toward describing these kinds of reserves with regard to the function they provide to the system– namely frequency containment (which acts fast to contain and limit frequency deviations), frequency restoration (which can act more slowly to restore the system frequency to its nominal value) and replacement reserves (which are brought online to replace the reserves that have just been used). A number of studies have already shown that inclusion of the need for operating reserves can have a significant impact on the results obtained from power system models (Palmintier, 2014, Welsch et al., 2014, van Stiphout et al., 2016) and this provides an argument for implementing them also in ESOMs. Because in ESOMs a technology is usually assumed to comprise an indefinite number of power plants[15], a stylized approach has to be followed (Vögelin et al., 2016), in which the technologies compete in both wholesale electricity and ancillary services markets. A technology can be logically divided into two parts: the part p participates in the electricity market, while the part pp participates in the ancillary services markets (Figure 2.7). A capacity transfer equation ensures that there is sufficient capacity for both electricity generation and provision of positive reserves. On the other hand, negative reserves can be implemented as constraints on the minimum electricity generation requirements. The trade-off between committing capacity to the electricity market versus grid balancing is based on the marginal cost of electricity production (in order to cover generation costs) and the marginal cost of capacity in the reserve market (which accounts as a revenue in order to cover fixed operating and investment costs).

The analyst may define also a maximum share of online capacity of each technology, according to which a technology can contribute to meeting negative reserves. The provision of positive reserves may not be dependent on the online capacities, since some

[15] Otherwise mixed integer programming can be employed to identify concrete power plant block sizes.

technologies can ramp-up fast enough to provide positive reserve without the need for any plants to be online.

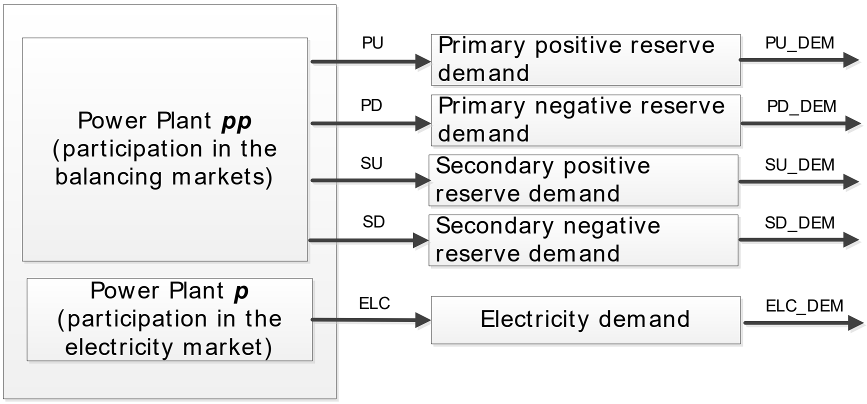

Figure 2.7: A stylized approach for introducing ancillary markets in ESOMs.

Following the approach presented in (Welsch et al., 2015) a power plant can be classified into one of the following three categories with respect to the provision of primary and secondary reserve, given that the analyst has specified the time horizon associated with each reserve type:

- Flexible technologies with high ramping rates, which can bring additional online capacity (or withdraw capacity) within the specified reserve timeframe to meet the reserve demand. The provision of positive reserve is constrained by the total available capacity, while the provision of negative reserve can be equal to the electricity generation capacity. Thus, there is no need to keep more capacity online than what is needed for electricity generation.
- Non-flexible units with low ramping rates, which can provide limited negative reserve (constrained by the ramping rates), which is not more than the difference between the current generation level and the minimum stable operation, and limited positive reserve (constrained by the ramping rates), which is not more than the difference between the maximum available capacity and the capacity committed for electricity generation). Thus, the capacity committed for electricity generation should exceed the minimum stable operation level and the provided negative reserves, while the total online capacity should be equal to the capacity committed for electricity generation plus all provided positive reserves.
- Technologies which cannot provide fast enough primary reserve but are suitable for secondary reserve. This implies a combination of the above two categories: the

provision of primary reserve requires an operation below the online capacity in order to ramp-up the generation if needed; the secondary reserve is constrained by the ramping characteristics and the total available capacity of a technology. The required minimum electricity generation has to be at least as high as the secondary negative reserve provided. Any additional primary negative reserve requires an operation above the minimum stable operation level

The demand for operating reserves can be determined endogenously by using a probabilistic approach (Hirth and Ziegenhagen, 2015) (see also Figure 2.8). First, the individual probability density functions (PDF) of the random variables regarding the forecast errors in electricity demand, in wind production and in solar production are estimated, either from historical data or theoretical considerations[16]. Then the joint density distribution is derived by means of statistical convolution. Additional random variables, e.g. plant outages, can also be included provided that there is an underlying probability density function that describes them. Finally, positive and negative reserves are set in a way that the area under the density function equals three standard deviations[17] (Doherty and O'Malley, 2005). For example, by assuming independence between demand, wind and solar forecast errors, the reserve requirements in hour t are:

$$R_t = 3 * \sqrt{\sum_k \left(\sigma_{D,k}^2 \cdot D_{k,t}^2\right) + \sum_m \left(\sigma_{S,m}^2 \cdot S_{m,t}^2\right)}$$

where $D_{k,t}$ is the electricity demand of end-use sector k, $S_{m,t}$ is the electricity generation of the stochastic RES option m, $\sigma_{D,k}$ is the variance of the probability density function of the forecast error of electricity demand in sector k, $\sigma_{S,m}$ is the variance of the probability density function of the forecast error of electricity production from the stochastic renewable source m. Additional terms, e.g. the loss of the largest unit (N-1 criterion) can be also included in the above equation (Hirth and Ziegenhagen, 2015).

[16] The most common approach is to assume a Gaussian distribution of the forecast error with mean 0 and standard error equal to the forecast error (Doherty and O'Malley, 2005, Ortega-Vazquez and Kirschen, 2009) or a hyperbolic distribution(Hodge et al., 2012)

[17] Since this is a non-linear equation, in LP models this expression has to be linearised, by applying techniques based on regression (Freedman, 2009) or stochastic linearisation (Socha, 2007) or simple linearisation.

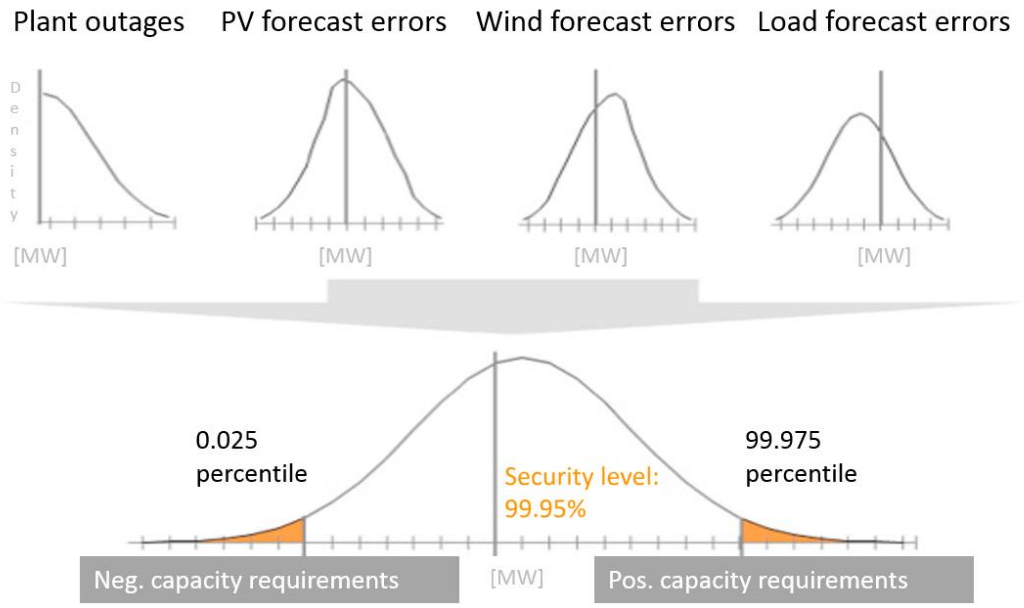

Figure 2.8: A probabilistic approach for ex-ante determination of requiring positive and negative control capacity (Hirth and Ziegenhagen, 2015).

The above approach implies different standard deviations for the PDFs of demand, wind and solar forecast errors for the different operational reserve types (primary, secondary and tertiary).

For example, by following this approach, standard deviations for demand wind and solar for primary reserve is 0.25%, 1.4% and 0.4% respectively in (Vögelin et al., 2016), while for secondary reserves is 1.3%, 6.0% and 5.9% in the same study. Similarly in (Welsch et al., 2015) the standard deviations of 1% and 1.4% were used for demand and the wind standard deviations respectively for assessing primary reserve requirements, while 2% and 6% for secondary reserves. The stylized approach described above requires assumptions on the maximum share of online capacity of each technology that can contribute to negative reserve provision. In addition, the analyst may introduce minimum shares of positive primary and secondary reserve that has to be provided from online plants, in order to avoid unrealistic situations when all the positive reserve is provided by offline units. A key assumption, though, is the forecast errors in wind, solar and electricity load. Moreover, they also need to make assumptions about the evolution of the quality of the forecasting techniques in the long-term and to the extent that different technologies can contribute to these reserves (Koltsaklis and Georgiadis, 2015). Another consideration is that the forecast error depends on weather and geographical conditions, as well as on technology sites, that if aggregated can lead to a decrease in the spread of forecasting errors (Wan, 2005).

2.4.2.2.3. Advantages and Limitations

Two approaches have been described with the aim of directly improving the technical representation in ESOMs each with their respective advantages and limitations.

The stylized integration of operational constraints has a key benefit in that it allows easy integration of different operational constraints the model that directly increase the optimality of the solution. However, given they are stylized, they do not explicitly capture the system constraints – they mimic them. This means that the validity of such integrated constraints cannot always be guaranteed and they often require calibration through use of more detailed models.

The methodology that integrates the requirement ancillary services into the optimisation of the system adds value to modelling result in that it allows for the increased optimality of the solution and captures a very influential technical constraint on system operation that is often omitted from such long-term planning models. An obvious limitation is that it requires the use of additional variables and constraints that increase the computation complexity required for a solution. Another is the uncertainty surrounding the endogenous sizing of operating reserve requirement over long time horizons, which makes the integration of these requirements into ESOMs challenging given the technological developments that may alter required operational reserves in future. A final limitation is that it requires an assumption on the evolution of the accuracy of the forecasting techniques regarding wind, solar and electricity load profiles.

2.4.3. Direct Integration Methodologies for IAMs

A very different approach to representing the integration challenges of wind and solar in large-scale energy-economy models (or IAMs) was developed by Ueckerdt et al (Ueckerdt et al., 2015b, Ueckerdt et al., 2016): the residual load duration curve approach. IAMs are used to analyse long-term mitigation strategies, and are therefore very complex – they need to include all energy sectors and carriers, all world regions, and cover the full 21st century. Adding hundreds of time-slices would increase the numerical complexity to a level that currently would make them computationally intractable. In contrast to other approaches that substantially increase the temporal resolution of the energy modelling tool, the residual load duration curve (RLDC) approach is based on a pre-analysis of detailed temporal data about load and generation from variable renewable energies (VRE) in order to extract the important dynamics and only implements these in the IAM. It takes advantage of the fact that many of the fundamental properties of a power system are contained in the RLDC (Ueckerdt et al., 2015a). An RLDC is the temporally reordered residual load that needs to be supplied by dispatchable power plants at a given share of VRE in the electricity generation mix (see Figure 2.9). The RLDC contains i) the peak demand that needs to be met by dispatchable capacities, ii) the number of hours that a certain capacity level is needed, and iii) the curtailment in times when VRE supply is larger than load. Because the RLDC ignores the chronology of the year, the RLDC and thereby these characteristics of a power system can be described quite accurately with a relatively small number of parameters.

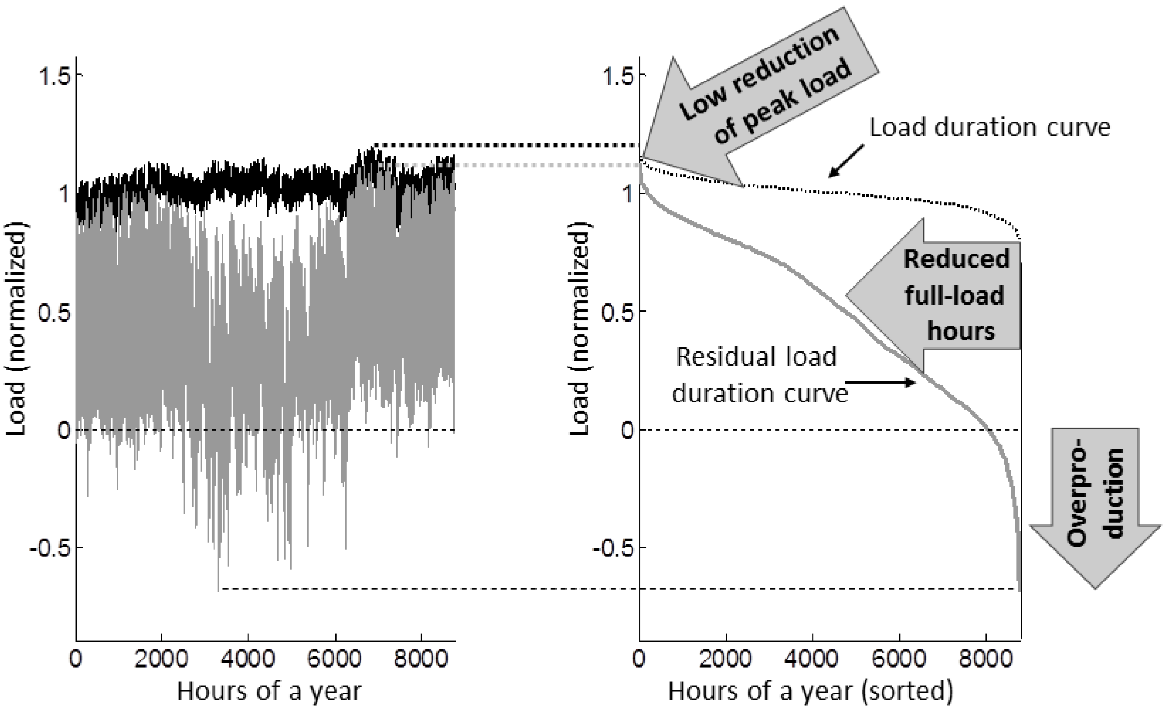

Figure 2.9: Chronological representation of load and its duration curve representation.The upper black line represents the load, while the lower grey line represents the residual load that needs to be covered by dispatchable power plants after adding 25% generation from wind and 25% generation from PV. To calculate the duration curves on the right, both load and residual load are reordered from highest to lowest value. The RLDC on the right shows three main challenges arising from including wind and solar: They do not fully contribute to the reduction of peak load, they lead to lower utilization of dispatchable power plants, and they can produce more than load, leading to curtailments.

The RLDC approach as implemented in the integrated assessment model REMIND (Luderer et al., 2014, Pietzcker et al., 2014, Luderer et al., 2015) is based on a direct representation of the dynamic changes of the residual load duration curve with increasing wind and solar generation (Ueckerdt et al., 2016). While the representative day approach presented in the following section uses a large number of time-slices to recreate the RLDC at various VRE shares, the RLDC approach uses only very few load bands to represent the shape of the RLDC but varies the height of each load band non-linearly depending on the share of wind and solar. Accordingly, the RLDC approach is only useful for non-linear models. The RLDC implementation in REMIND increased model runtimes by a factor 3-5.

In REMIND, the RLDC is represented through six values: four load bands representing the shape of the RLDC curve, a superpeak capacity requirement, and the amount of curtailment (see Figure 2.10). Each of these 6 values is represented by a third-order polynomial that depends on the relative contribution of PV and wind to load (see Figure 2.11 to see how the height of the superpeak decreases with increasing wind and solar share). The model ensures that sufficient dispatchable capacity is installed to cover each load band, and calculates the resulting capacity factors from the full load hours of a load band. For a more detailed description including a full parameterization for all world regions, see (Ueckerdt et al., 2016).

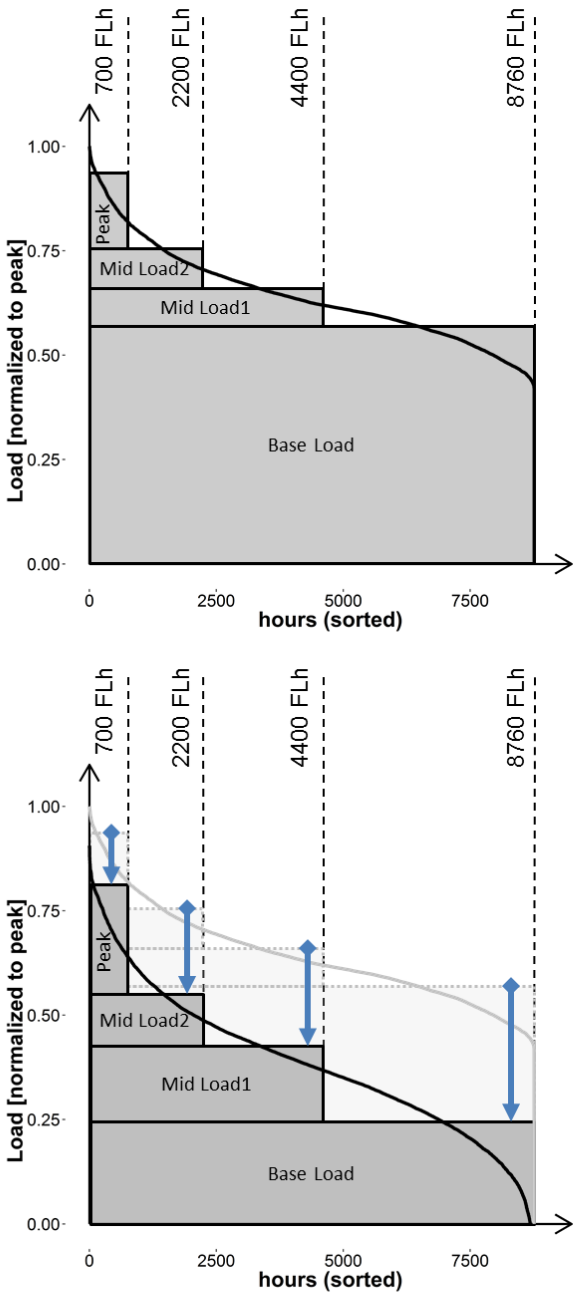

Figure 2.10: Representation of RLDCs in REMIND in a discretized form with the help of four load bands. Left: Black line represents the RLDC at 0% VRE; the load band heights of the four load bands are fitted to best represent the RLDC. Right: At a wind share of 40%, the RLDC is decreased (black curve). According to the changing slope of the RLDC, the reduction of load band heights (as shown by the blue arrows) is very different across the different load bands. The height of the base load band is reduced much stronger than the height of the mid and peak load bands.

The REMIND model intertemporally optimizes the investment into both VRE and dispatchable capacities to meet a price-elastic electricity demand. In climate mitigation scenarios, carbon prices increase the cost of conventional power plants, so that more wind and solar power is deployed. As wind and solar shares increase, the base load band shrinks in comparison to the mid and peak load bands (see Figure 2.10, right). Accordingly, the model will over time replace the current power system consisting of a large share of baseload plants and invest more into dispatchable power plants with low capital intensity, such as open-cycle gas turbines or hydrogen turbines.

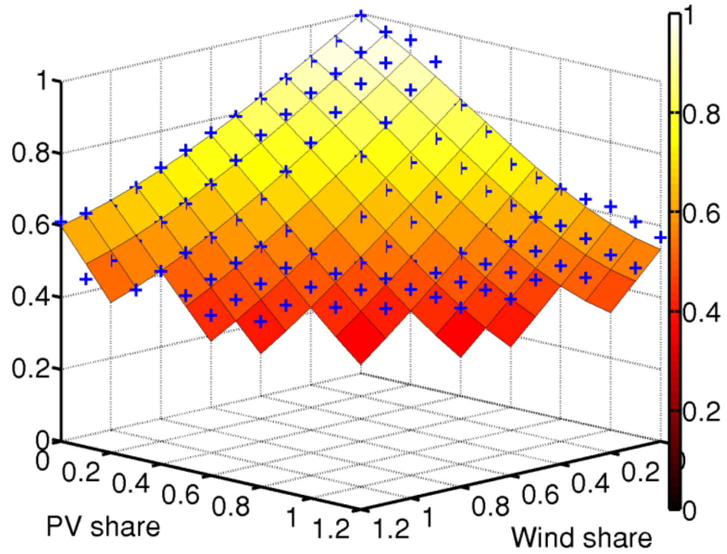

Figure 2.11: Change of the superpeak value (z-axis) with increasing wind and solar share (x/y-axes), assuming use of short-term storage (Ueckerdt et al., 2016). The depicted values are normalized to the superpeak value in a system without wind or solar. Blue crosses represent individual DIMES model runs, the coloured surface represents the third order polynomial representation in REMIND. In x/y direction, blue crosses sit at the crossing of black surface lines – if the crosses are fully visible, they have a value larger than the polynomial fit, if the crosses are clipped or hidden by the surface, they have a value lower than the polynomial fit.

While the REMIND full implementation of the RLDCs requires the use of non-linear solvers to represent the third-order polynomials, the MESSAGE model includes mixed-integer approximations of some of the key characteristics of the RLDC, such as the VRE-share-dependent contribution of wind and solar to covering peak demand, or VRE-share-dependent flexibility requirements (Johnson et al., 2016).

As the RLDC contains no information on chronology, the use of short-term storage such as pumped hydro storage or battery storage is difficult to implement endogenously in this approach. The reason is that short-term storage technologies like batteries are relatively costly and have especially high reservoir costs, thus they are most competitive if times with overproduction and times with high demand alternate frequently – therefore, photovoltaics with its diurnal variation is a natural complement for short-term storage. However, an RLDC does not contain any information whether or not the times with high demand on the left side of the RLDC alternate with the hours of overproduction on the right-hand side of the RLDC.

To still include the effect of short-term storage in RLDC-based approaches, it is necessary to pre-process the RLDC data and derive some proxy for the periodicity of the residual load. For the RLDCs developed in (Ueckerdt et al., 2016), the one node full year hourly dispatch and investment model DIMES was used to calculate cost-optimal short-term storage deployment at different wind and solar shares on the basis of the load and generation time series with full hourly detail over the year. In a way, this process has similarities with the uni-directional soft-linking described in 3.1 but acts in the opposite direction: the highly detailed model is used to parameterize the inputs to the IAM. For the implementation in REMIND, the short-term storage capacities calculated by DIMES are also parameterized by a third-order polynomial depending on wind and PV shares, and input as requirements into REMIND. While this required investment into storage results in additional costs to the electricity system, it also leads to an RLDC with reduced curtailment and reduced peak demand, as can be seen in Figure 2.12.

In contrast, long-term/seasonal storage can be endogenously represented with the help of the RLDC, because it relies on filling and emptying the reservoir only once per year. The model can use curtailed electricity from the right of the RLDC to produce hydrogen, which then can either be used in other sectors or in hydrogen turbines to provide dispatchable generation at times of high residual demand.

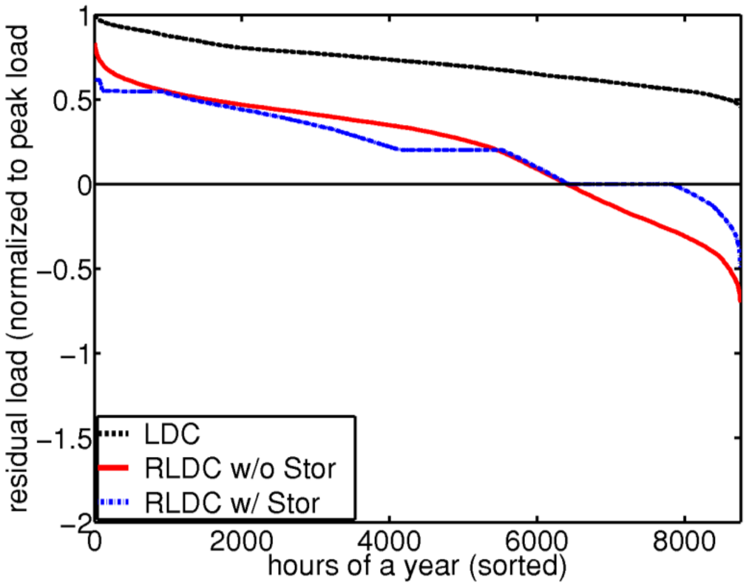

Figure 2.12: Effect of short-term storage deployment in DIMES on the RLDC for Europe with a gross contribution (gross meaning "before curtailments") to a load of 30% from wind and 40% from PV. The LDC is displayed in black. Compared to the RLDC before use of short-term storage (red), the RLDC with storage (blue) shows much lower residual peak demand and less curtailment.

2.4.3.1. Advantages and Limitations

The main advantage of the RLDC-approach is the reduction of complexity through pre-processing of load and VRE generation time series. This enables a decent representation of the power system with a relatively small number of parameters: six variables, each represented by a third-order polynomial, capture the most important power sector characteristics, as shown by a comparison of REMIND results with the hourly power sector model REMIX(Pietzcker et al., 2017).

There are, however, a number of limitations to this methodology:

- Due to the loss of chronology, short-term flexibility (ramping) constraints cannot be explicitly represented. However, as the RLDC captures the shift to low capacity factors at high shares of VRE, it will result in power systems with high amounts of low-capital cost power plants such as gas or hydrogen combustion turbines, which should ensure sufficient flexibility.
- There are also issues regarding the spatial aspect of VRE integration (pooling, impact of grid extensions) in that these effects cannot be calculated from RLDCs, but rather need to be accounted for already in the original data from which the RLDCs were derived.
- While the effect of using short-term storage cannot be directly calculated from the RLDC in REMIND itself, it was be implemented in an approximate way through a

pre-processing step: cost-optimal storage capacities at different wind and solar shares are calculated with the help of a smaller dispatch and investment model with high temporal resolution, and this information is basis for the REMIND investments into VRE, storage, and dispatchable capacities.

2.5. Discussion and Conclusions

The aim of this work was to review the current state of play with regards to how integration challenges of VRE are represented in ESOMs and IAMs. A key motivator in this was to aid future research by presenting and contrasting these methodologies so that, in future, energy system modellers can select and apply methodologies best suited to their situation. Failure to sufficiently capture the integration challenges of VRE can lead to unrealistic assessment of the difficulty associated with achieving a low carbon energy system and thus lead to sub-optimal energy system planning.

The presented methodologies all have their own strengths and limitations but also differ in their ease of use. To aid the discussion, Table 2.1 presents an overview of the different methodologies and their respective advantages and disadvantages.

Table 2.1: Tabular comparison of modelling methodologies

Methodology		**Strengths**	**Limitations and challenges**
Soft-link to an operational power system model	Uni-directional soft-link	• Accurate assessment of operational costs, fuel consumption and greenhouse gas emissions • High level of temporal and technical detail allows assessment of power system reliability. • Good robustness check of energy system model results	• Need for a UCED model in addition to the ESOM/IAM • Does not increase the optimality of the solution: • Can possibly overestimate integration costs of VRE, because the ESOM investments are not adjusted to account for the UCED challenges
	Bi-directional soft-link	• Allows for increased optimality of the solution • Iterative procedure has a lower computational cost than a single integrated ESOM/IAM with the same level of detail	• Need for a UCED model in addition to the ESOM/IAM • Feedback to ESOM/IAM highly dependent on modeller skill and judgement • Optimality and convergence of the

		• Accurate assessment of costs, fuel consumption and greenhouse gas emissions • High level of temporal and technical detail allows assessment of power system reliability. • Good robustness check of energy system model results	solution cannot be guaranteed
Direct integration methodologies for ESOMs	Semi-dynamic balancing using typical days with increased resolution	• Allows for increased optimality of the solution • Ease of implementation • Retains chronology which allows the capture of the benefits associated with within-day storage systems and other types of flexibility	• Averaging of VRE generation data of different days leads to smoothing of VRE output. • Reliable operation of the modelled power system in the short term (hourly) is difficult to assess • Endogenous determination of the value of flexibility requires to include additional constraints, which further increase computational cost • Computational complexity increases with an increasing number of time-slices
	Integral balancing based on approximating the joint probability distribution of the load and VRE generation	• Allows for increased optimality of the solution • The variability of the load and VRE generation can be captured relatively well using a limited number of time-slices • The correlation between different time series is	• Chronology is lost making it impossible to assess the need for flexibility and the value of flexibility options • Reliable operation of the modelled power system in the short term (hourly) is difficult to assess

		accounted for. This way, the RLDC will be approximated well for varying shares of VRE. • Ease of implementation	
	Semi-dynamic balancing using representative historical periods	• Allows the strong increase of the optimality of the solution • The variability of the load and VRE generation can be captured well using a limited number of time-slices • The correlation between different time series can be accounted for. This way, the RLDC will be approximated well for varying shares of VRE. • Retains chronology which allows an endogenous determination of the value of flexibility options such as within-day storage.	• Reliable operation of the modelled power system in the short term (hourly) is difficult to assess • Good selection of representative historical periods requires implementation of a specific selection algorithm/model • Difficult to capture the impact of medium-term variations (e.g., periods of two weeks with almost no wind) • Endogenous determination of the value of flexibility requires to include additional constraints, which further increase computational cost
	Using stochastic programming as a means to address modelling uncertainties	• The requirement for back-up capacity is endogenous removing the need for a commonly used peak constraint. • Hedges against not having enough flexibility generation capacity in the power system. • Detailed quantification of uncertainty	• Strongly increases computational complexity • Stochastic modelling requires a representation of the uncertain parameters that are specific to the model used • Requires advanced scenario tree generation techniques and reduction algorithms

		• Can be combined with methodologies that increase intra-annual time resolution • Can incorporate several historical RES profiles • Measures the costs of disregarding uncertainty • Measures the cost of eliminating uncertainty (and hence provides insights about the order of magnitude of supports required in investments in back-up capacity and storage options)	• Requires a solid understanding of probability concepts and sampling techniques • Can impose difficulties in interpreting the results obtained
	Stylized integration of operational constraints	• Allows for increased optimality of the solution • Ease of implementation • Allows to mimic the impact of different constraints with only a minor increase in computational complexity	• Requires calibration using more detailed models • General validity cannot be guaranteed
	Modelling ancillary services markets in long-term energy system models	• Allows to increase the optimality of the solution • Captures the most influential technical constraint • Can be combined with a low level of temporal detail •	• Uncertainties related to endogenous sizing the need for operating reserves over long time horizons • Requires using additional variables and constraints which increase computational complexity

Direct integration methodologies for IAMs	Parametrization of residual load duration curves	• Allows for increased optimality of the solution • The correlation between different time series is fully accounted for. This way, the RLDC will be approximated well for varying shares of VRE • Only a requires a limited increase in computational complexity compared to a time-slice approach	• Chronology is lost, making it impossible to directly assess the need for flexibility and the value of flexibility options • Parametrization of the impact of short-term storage requires pre-processing of the RLDC using a more detailed model • The spatial aspect of VRE integration (effect of transmission grid on pooling variability) cannot be endogenously calculated, but rather needs to be included in the RLDC data ex-ante. • Reliable operation of the modelled power system in short-term (hourly) is difficult to assess

Indirect soft linking approaches require the construction of new dedicated sectoral models and – more challengingly –handling the interface between the two models in order to arrive at consistent results. This allows for a good robustness check of energy system model results by leveraging the strengths of an operational power system model to gain additional insights into long term energy system model results. If it is a bi-directional soft-link then it also allows for increased optimality of the solution. The use of operational modelling means that also better assessment of operational costs, fuel consumption, greenhouse gas emissions and power system reliability (in terms of generation adequacy) is possible.

A key strength of direct integration methodologies for ESOMs and IAMs discussed in this chapter is that they are directly integrated into the model optimisation thus eliminating the need for an iterative approach as is required in the bidirectional soft-link approach. A key strength of such approaches improving the temporal representation in ESOMs is that they all allow for the better capture of variability of load and VRE generation. The use of stochastic programming and probability derived temporal representation also helps ensure that a wide range of possible outcomes are captured in the model optimisation. This makes the power system more robust in relation to modelling uncertainties. A common limitation of these approaches is that operation of the modelled power system in the short term remains difficult to assess; this is also true of the approach outlined for IAMs. The direct integration methodologies for ESOMs that improve the technical representation directly improve the solution attained. This is to say that improving the technical representation of these models makes the models less approximate in their representation of factors that influence power system operation which lead, in principle, to a solution that is better suited to society's needs. The stylized integration of operation constraints are easy to implement and the integration of ancillary services markets in ESOMs allow the capture of an influential technical constraint on system operation. Generally, the challenge of the use of such approaches is that they require careful calibration to ensure validity and not doing so can lead to inaccurate assessment of VRE integration potential. In IAMs, the parameterization of RLDCs are effective in representing correlation between different time series thus making the RLDC well approximated well for varying shares of VRE while requiring only a limited increase in computational complexity. Loss of chronology makes it impossible for it to directly assess the value of flexibility measures and to thus assess the value of short term storage requires use of a separate more detailed model. This approach for IAMs also cannot endogenously capture the spatial element of VRE integration meaning it needs to be included in the RLDC data ex-ante.

From this review it is evident that there are clear advantages and disadvantages to all the approaches discussed. Thus, it is apparent that the choice of methodology is highly dependent on the modelling situation to which it is to be applied regarding the models used, modeller skill and data availability. This work, by comparing a whole variety of approaches and identifying their strengths and limitations, helps modellers in their selection of a methodology best suited to them.

There are certain principles that have been identified as guides for addressing flexibility in energy models such as careful consideration of model simplifications, definition of appropriate temporal and geographic resolution, definition of system flexibility constraints and model validation (Hidalgo Gonzalez et al., 2015). The inherent differences between the methodologies mean that each will integrate short term variations differently into the modelling process and assess the flexibility of the system differently. To date these methodologies have been applied successfully to separate models and data sets, making it difficult to compare results. Future work is required to effectively compare strengths and weaknesses of the different approaches, this is a key hotspot for future research in this area.

There are a number of avenues down which such research could be furthered. Any such work comparing methodologies should apply methodologies to the same region using the same data sets in order to increase comparability and reduce own-model bias in the evaluation. An example of such work are studies to directly compare methodologies that directly improve the temporal & technical representation respectively within long term planning models. This would quantify directly the trade-offs made when selecting a methodology to apply. Other work could be done to analyse the impact of improving the technical & technical representation of models in tandem. This could be done by applying various levels of technical representation in the model and coupling these additions with various levels of temporal representation. Such work would provide clarity on how the implementation of certain methodologies impact on one another and also how impactful certain technical elements become under various temporal representations in long term models and vice versa. These suggestions for future work would also benefit from uni-directional or bi-directional soft-linking which could operationally analyse under high resolution the various power sectors projected and give insights into their operational realisation. Such analysis would provide clarity on the variety of results achieved by the different methodologies and lead to better estimation of the effort required to transition to an energy system with high proportions of renewable power generation which would, in turn, lead to better informed development of energy policy.

Chapter 3: Adding Value to EU Energy Policy Analysis Using a Multi-Model Approach With an EU-28 Electricity Dispatch Model

3.1. Abstract

The European Council has agreed ambitious EU climate and energy targets for 2030, including a 40% reduction in greenhouse gas emissions compared to 1990 levels and a minimum share of 27% renewable energy consumption. This chapter investigates the challenges faced by the European power systems as the EU transitions towards a low carbon energy system with increased amounts of variable renewable electricity generation. The research here adds value to, and complements the power systems results of the PRIMES energy systems model that is used to inform EU energy and climate policy. The methodology uses a soft-linking approach that scrutinizes the power system in high temporal and technical detail for a target year. This enables generation of additional results that provide new insights not possible using a single model approach. These results point to: 1) overestimation of energy generation from variable renewables by 2.4% 2) curtailment in excess of 11% of energy available from variable renewables in isolated member states 3) EU interconnector congestion (lines operating at full capacity) average of 24% [1]

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[1] Published as: COLLINS, S., DEANE, J. P. & Ó GALLACHÓIR, B. 2017. Adding value to EU energy policy analysis using a multi-model approach with an EU-28 electricity dispatch model. Energy, 130, 433-447.

3.2. Introduction

The European Council agreed in October 2014 (European Council, 2014) ambitious targets for energy and climate change mitigation for 2030, namely to achieve i) a 40% reduction in greenhouse gas (GHG) relative to 1990 levels, ii) a 27% share of energy use from renewable sources and iii) a 27% improvement in energy efficiency. Energy system modelling is used to project technology pathways that meet these targets and is a crucial part of long term energy planning. Energy systems models determine optimal pathways for this transition by selecting technologies that enable stringent emissions reduction targets to be met at least cost whilst accounting for technical constraints that will govern this transition. Such ambition regarding European emissions reduction imply an expected high penetration of variable renewable electricity generation in future (European Commission, 2014). However, from an engineering perspective, such technologies pose a number of challenges relating to the adequacy and reliability of the power system at high penetrations. Long term energy system models have a wide sectoral focus and detailed modelling is required to ensure a reliable power system to properly assess the integration challenges that high penetrations of variable renewables bring. To achieve the significant emissions reductions required, long term planning must also consider the potential benefits of a variety of factors such as flexibility measures in combination with better integration between the electricity sector and various other sectors of the economy such as thermal & transport sectors which has been shown to enable penetrations of variable renewable generation in excess of 80% in the electricity sector (Connolly et al., 2016).

The primary software model used to inform EU climate and energy policy is PRIMES, a partial equilibrium model of the European Union energy system developed by the National Technical University in Athens (Capros et al., 2015, Capros et al., 2012a, Capros et al., 2012b, European Commission, 2013a) for scenario analysis and policy impact studies. The model was used to assess the impacts of EU GHG mission reduction scenarios for the period to 2030 that in turn informed the European Council's decision (European Commission, 2014). The impact assessment considered different levels of ambition relative to a *Reference scenario* (PRIMES-REF), i.e. a scenario exploring the consequences of current trends including full implementation of policies adopted by late spring 2012 in the European Union. The impacts of different levels of GHG emissions reduction, renewable energy penetrations and energy efficiency ambitions were assessed relative to PRIMES-REF. PRIMES-REF assumes that the EU will meet the target (under Directive 2009/EC/28) for a 20% share of renewable energy penetration by 2020; the target of 20% GHG emissions reduction by 2020 relative to 1990 levels (under Directive 2008/EC/29 for ETS emissions and Decision 406/2009/EC for non-ETS emissions) and that the Energy Efficiency Directive (Directive 2012/EC/27) will be fully implemented. In addition PRIMES-REF includes assumptions that all other policy goals legislated for prior to Spring 2012 (including for example the regulation on car manufacturers regarding light duty vehicles (Regulation 403/2009/EC) will also deliver anticipated targets. The PRIMES-REF scenario extends to the year 2050 and the results indicate that by 2030 the EU can achieve GHG emissions reductions of 32% below 1990 levels; 24% penetration of renewable energy and 21% energy efficiency gains.

Long term energy system planning decisions are commonly underpinned by analyses using long term energy systems models, as is the case with PRIMES for the EU. However, in terms of the power sector such models can encounter difficulties in assessing the challenges associated with a low carbon transition (Collins et al., 2017b). This work addresses a gap in long term planning by operationally analysing, under high technical and temporal resolution modelling, the realisation of ambitious carbon reduction policy for the European power sector. This provides insights that are not directly possible in long term models such as PRIMES, as in direct quantification of interconnector congestion, electricity curtailment and market pricing. The quantification of these and other elements allows for better assessment of the difficulty of integrating significant shares of renewable generation. This work also allows closer study of challenges they create for conventional generation which can be heavily impacted by reduced market pricing and reduced capacity factors due to the merit order effect displacing them in the generation stack.

The difficulty energy systems models have in sufficiently accounting for operational dynamics of the power sector owe largely to the breadth of their focus, which span many sectors of the economy, in which the power sector is typically represented in a stylised way with a limited number of time slices to make the models computationally manageable. Low levels of detail in the modelling of the power sector can lead to an overestimation of the value of baseload technologies and variable renewable generation, while the value of flexible generation technologies with higher generation costs can be underestimated (Poncelet et al., 2016a). On the other hand, crude representations of integration challenges such as upper limits on variable renewable generation can lead to an overestimation of the cost of meeting emissions reduction targets (Pietzcker et al., 2017). A number of methodologies have been developed to improve the representation of challenges associated with a low carbon transition of the power sector in such long term models (Poncelet et al., 2016a, Pfenninger et al., 2014, Hidalgo Gonzalez et al., 2015, Pietzcker et al., 2017).

This chapter builds on previous literature by applying a multi-model approach (Deane et al., 2012), as described in section 2.4.1 of chapter 2, using results from the PRIMES model to construct a 28 Member State power system model. In previous work, multi-model approaches were used to analyse results for the Irish TIMES model and the Italian MONET model, where valuable insights were gained in terms of the increased need for flexibility (so as to ensure the portfolio outputted is capable of meeting power demand with an increased variability of power production) and careful incentivisation of investment to promote adequate capacity expansion plans in a low carbon future for electricity (Deane et al., 2015b, Deane et al., 2015a, Deane et al., 2012). Other work using the OSeMOSYS modelling framework, as in (Welsch et al., 2014), use a multi model approach and highlight how such an approach can lead to a better assessment of costs and how many long term models can underestimate the costs of meeting long term emissions reduction targets. More highly resolved modelling in terms of both technical and temporal resolution allows detailed assessment of the output of these models than was possible in their original development.

The heating and cooling strategy issued by the European Commission advocates increased synergies between sectors via district heating and cooling, smart buildings and cogeneration of heat and power to reduce the cost of the energy system (European Commission, 2016c). An additional scenario was simulated to determine the impact of demand response in the power system model simulation, though this does not capture important sectoral interactions that would be critical to its implementation. Previous work has included analysis of this sectoral integration using other models to compensate for similar PRIMES scenarios (Connolly et al., 2014, Lund et al., 2014b, Connolly et al., 2016).

However, these analyses do not account for the significant impact of interconnector flows between Member States and their application thus generated different insights. It is therefore apparent that the various analyses and models supplement one another and make way for a more holistic view of how best to decarbonise the European energy system.

This work considers the results of the publicly available 2013 PRIMES-REF for the year 2030, and uses them as a starting point for further analysis, with a particular focus on the results for the power system. PRIMES REF includes full implementation of current EU policies that were adopted by spring 2012 and does not represent potential avenues for policy development that have been proposed since that time such as those proposed in latest European Commission winter energy package (European Commission, 2016g). This work uses these PRIMES-REF results to build and run a unit commitment & economic dispatch model using PLEXOS Integrated Energy Model (hereafter referred to as the UCED scenario model). This enables additional analysis to be carried out using the added value that a power systems model with higher temporal resolution and technical detail can bring, namely to quantify at Member State level levels of curtailment of variable renewable electricity, interconnector congestion and wholesale electricity prices. This approach also allows for the analysis of the operational impacts of demand response and those of the maintenance of sufficient levels of grid inertia which are required for frequency stability.

While power system models and energy systems models both model electrical power systems they are profoundly different modelling tools regarding their practical aim. Dedicated power system models typically focus solely on the electricity system with significantly higher technical and temporal resolution. The primary inputs to power systems models can consist of electrical load, fuel prices and the technical attributes of power plants and transmission systems. Whole energy systems models by contrast, model electrical generation endogenously and are driven by the combined behaviour of end use sectors (that are driven by exogenous energy service demands) and by the supply sectors that deliver primary fuels. The focus of an energy systems model is to provide a technologically rich basis for determining energy pathways over a variety of time horizons from the medium-term (Up to 30 years) to long-term (Between 50 and 100 years). Power system models on the other hand have typically much shorter time horizons. Due to the dedicated problem focus of these models on the power sector, the sector can be examined at significantly higher resolution in comparison to energy system models which deal with a much wider set of problems which makes them complementary to each other (Deane et al., 2012). The problem in the power system model in this work, is focused on the dispatch of power generation at least cost to meet an electrical demand but all the while obeying the technical constraints and capabilities of the power system. This problem is often referred to as Unit Commitment and Economic Dispatch problem and these models typically have a time horizon of one year. Such power system models can also be used for analysing shorter term power system dynamics or indeed long term capacity expansion planning. A variety of models are used for power system studies and are detailed in (Foley et al., 2010).

The purpose of the chapter is to enhance and to check the robustness of the results for electricity generation of the PRIMES-REF scenario for the year 2030. It does this by using the PRIMES-REF results to build a UCED scenario model. It then utilises the increased technical and temporal resolution of the dedicated power systems model to scrutinise the PRIMES-REF results for the year 2030. The UCED scenario model adds value by generating new results with PLEXOS that provide new insights to the results from PRIMES. In particular, the power system model quantifies i) variable renewable electricity curtailment; ii) levels of interconnector congestion and iii) wholesale electricity prices.

In the UCED scenario model, the power system is modelled in detail at Member State level, the model runs at hourly resolution for the full target year of 2030 whereas PRIMES uses a maximum of up to 9 typical days at hourly resolution in the extended model version (E3MLab/ICCS, 2014). The power system model uses individual hourly electricity generation profiles for solar and wind power for each Member State based on local conditions and capacities for the year 2030, predicted electricity hourly demand profiles for the year 2030 and generation profiles for all other methods of electricity generation outlined in PRIMES (Hydro, Solids Fired, Oil Fired, Gas Fired, Biomass waste etc.) The model also considers the levels of interconnection between Member States, demand response and the maintenance of sufficient levels of grid inertia across the European Union.

To give context on the level of ambition regarding PRIMES REF in terms of renewable electricity generation, particularly variable renewable electricity generation, Table 3.1 was constructed. Power system issues associated with variability are well documented by the

IEA (Gul and Stenzel, 2005, Chandler, 2011). Variability poses a number of challenges for power systems particularly in the areas of system balancing, unit commitment and economic dispatch. This variability leads to the increased flexibility being required in the generation mix for system balancing. Flexibility measures such as demand response (Katz et al., 2016, Nezamoddini and Wang, 2016), power to gas (Meylan et al., 2017, Ahern et al., 2015), power to heat (Böttger et al., 2014, Ehrlich et al., 2015), CAES (Amoli and Meliopoulos, 2015), thermal storage (Stinner et al., 2016), pumped hydro storages (Klumpp, 2016, Barbour et al., 2016) and increased power plant flexibility (Garbrecht et al., 2017) will be critical in the integration of significant portions of variable renewable power (Papaefthymiou et al., 2014). European energy policy development must ensure conditions are favourable for investment in this area, drawing all flexible resources regarding generation, demand and storage, into the market through use of proper incentives and a market framework better adapted to them (European Commission, 2016f).

Increasing penetrations of variable renewable power have been shown to impact the frequency, voltage, transient and small signal stability of the power system, a review of these impacts is found in (Flynn et al., 2017). High penetrations of non-synchronous modes of generation such as wind and solar photovoltaic alter the response of the power system for faults and contingencies by reducing the on-line system inertia (Sharma et al., 2011, Wang et al., 2016). This in turn raises concerns regarding the maintenance of power system reliability at high penetrations of such modes of generation. It is the non-synchronous nature of variable renewable generation such as wind and solar photovoltaic sources that means they do not currently contribute to grid inertia (although this is an active area of research (Ekanayake and Jenkins, 2004, Yingcheng and Nengling, 2011)). Grid inertia refers to the stored rotational energy on the system required to mitigate frequency fluctuation and to limit the rate of change of frequency (RoCoF) in the event of a sudden generator outage or failure of critical electrical infrastructure (AEMO, 2013). Inertia may be a cause for concern for certain Member States in future and is currently of particular concern to relatively small isolated power systems such as Ireland (Eirgrid, 2017).

Table 3.1 details the percentage contribution of renewable energy sourced electricity (RES-E) and variable renewable energy sourced electricity (VRES-E) generation by member state in terms of gross electricity generation for the year 2014 (Eurostat, 2015b), and for 2030 according to the PRIMES REF scenario. VRES-E is defined as wind and solar electricity production. The values at EU level are also shown, along with the values for the PRIMES GHG40 scenario. The PRIMES GHG40 Scenario is a scenario run of PRIMES in which the level of ambition extends beyond that of the 2030 PRIMES REF scenario, in 2030 it attains a 40% GHG reduction and by 2050 an 80% GHG reduction compared to 1990 levels. It is set with enabling conditions that are modelled by altering modelling parameters with respect to those included in the Reference conditions. The enabling conditions are assumptions that act independently of carbon prices/values or economic or regulatory incentives for renewables and energy efficiency (European Commission, 2014).

Table 3.1: Percentage contribution of renewable electricity (RES-E) and variable renewable electricity (VRES-E) generation by member state in terms of gross electricity generation

	2014		2030 PRIMES REF		2030 PRIMES GHG40	
Country	**RES-E (%)**	**VRES-E (%)**	**RES-E (%)**	**VRES-E (%)**	**RES-E (%)**	**VRES-E (%)**
Austria	70.0	6.5	88.9	20.1		
Belgium	13.4	8.0	42.9	30.5		
Bulgaria	18.9	6.8	17	8.7		
Croatia	45.3	4.1	69.5	11.7		
Cyprus	7.4	6.2	31.5	29.4		
Czech Republic	13.9	3.8	14	3.5		
Denmark	48.5	36.2	73.1	58.8		
Estonia	14.6	6.6	31.2	22.4		
Finland	31.4	1.3	30.3	6.7		
France	18.3	4.7	37.7	23.6		
Germany	28.2	16.1	52.5	37.1		
Greece	21.9	13.4	44.4	26.9		
Hungary	7.3	1.8	15.5	6.9		
Ireland	22.7	18.2	66.1	58		
Italy	33.4	11.6	48.5	25.3		
Latvia	51.1	1.9	67.7	18.3		
Lithuania	13.7	6.4	13.2	2.2		
Luxembourg	5.9	2.6	43.6	26.3		
Malta	3.3	3.0	37.9	35.8		
Netherlands	10.0	5.6	36.2	26.1		
Poland	12.4	4.7	16.7	8		
Portugal	52.1	23.5	88.5	57.9		
Romania	41.7	13.0	46.3	12.7		
Slovak Republic	23.0	2.2	24	4.9		
Slovenia	33.9	1.8	34.8	6		
Spain	37.8	24.0	48.2	35.3		
Sweden	63.3	8.1	57.5	7.4		
United Kingdom	17.8	10.0	50.3	44		
EU28	27.5	11.0	44.5	26.8	49.3	30.3

The difference between 2014 and PRIMES REF 2030 are very considerable, most notably from an operational standpoint in terms of VRES-E penetration. However, the difference between PRIMES REF and PRIMES GHG40 scenario results for 2030 are not significant with a difference of RES-E and VRES-E penetrations of 4.8 percentage points and 3.5 percentage points respectively. This small difference in penetration of RES-E and VRES-E enable the results of this work to be considered a proxy for broadly assessing penetration rates that that would be achieved under the more ambitious 2030 PRIMES GHG40 scenario, providing insights regarding the challenges associated with significant penetrations of variable renewable generation. In addition the difference in ETS price between 2014 levels (€6/tonne CO_2) and PRIMES REF (€35/tonne CO_2) is significantly higher than the difference between 2030 PRIMES REF and 2030 PRIMES GHG40 (€40/tonne CO_2).

3.3. Modelling Tools

3.3.1. PLEXOS Integrated Energy Model

PLEXOS is a tool used for power systems modelling[2] (Energy Exemplar, 2018a) that can be used for integrated modelling of power, water and gas systems. It is a commercial modelling tool used for the planning of power systems and simulation of electricity markets. It has also been used in many academic applications for non-commercial research and it is free of charge for such work. In this chapter, the focus is on the least cost unit commitment and economic dispatch of the electricity system, with a focus on a single year (2030).

The setup of the model is focused on the minimisation of overall system operation cost. This minimisation is subject to constraints relating to the dispatch of electricity such as operational attributes of generators, availability of generators, system operation and transmission constraints and fuel & emissions costs. Models can be solved through use of linear or mixed integer linear programming. This work used rounded linear relaxation which enabled faster solution times than full integer optimal solutions because it made use of a limited number of passes of linear programming which is less computationally intensive than integer programming while maintaining significant precision. In PLEXOS, the

[2] PLEXOS can also model integrated energy systems, combining water, gas and electricity systems modelling

mathematical formulations behind the model are openly available for inspection, making it transparent. In this work, the model was run using XPRESS-MP provided by FICO to solve the model (FICO, 2018).

In power system operation, many renewables such as power generation from wind and solar operate by effectively bidding at zero for each dispatch period due to their lack of fuel costs. The very nature of these modes of generation significantly differ to conventional generators and raise new challenges regarding to power system operation such as increased ramping requiring and reduced market pricing to name but a few. These challenges are largely due to the inherent variability, non-dispatchability and non-synchronous nature of these modes of generation.

Given the large amount of renewable electricity generation expected to come online to meet the ambitious targets in the EU (even in the PRIMES-REF scenario), accurate modelling of these variable renewable resources is very important and merits strong consideration in policy development. The increasing amount of variable renewables anticipated in the EU-28 in order to meet ambitious renewable energy targets means that the modelling of this variability from an operation standpoint is of paramount importance.

The operational simulation of the realisation of such ambition, in the context of unit commitment and economic dispatch, enables detailed assessment of the challenges associated with a transitional low carbon electricity sector.

3.3.2. PRIMES Energy System Model

The PRIMES Energy System Model is a model of the European Union energy system. It is a partial equilibrium model that is the result of a number of collaborative projects supported by the Joule programme of the Directorate General for Research of the European Commission. The model focus is on the medium to long term time horizon and it is used for a variety of tasks including forecasting, scenario analysis and policy impact studies. PRIMES is modular in nature and allows for use of a united full model or indeed partial use of some of its modules to support specific studies. It is a behavioural model that also explicitly captures the demand, supply and pollution abatement technologies relating to energy use (E3MLab/ICCS, 2014).

Because PRIMES is a partial equilibrium model, the model results form a partial equilibrium solution. This means that supply and demand of energy attain an equilibrium in every scenario but model feedback is not provided to the rest of the economy for alternative pathways for the energy system that is generated in each scenario

Figure 3.1 illustrates the PRIMES model structure, including the inputs to the model and the different scenarios generated. PRIMES-REF is the EU Reference Scenario, which describes the impacts of current trends which include full implementation of current European policy that were adopted by spring 2012. The PRIMES-REF gives an indication of the anticipated developments with regard to policies that have been agreed out to the year 2050. PRIMES-REF allows for the assessment of the effect of current policies and how they relate to achieving long term goals, serving as a comparison for other policy scenarios with varying levels of ambition regarding reduction of emissions, development of renewable energy and energy efficiency.

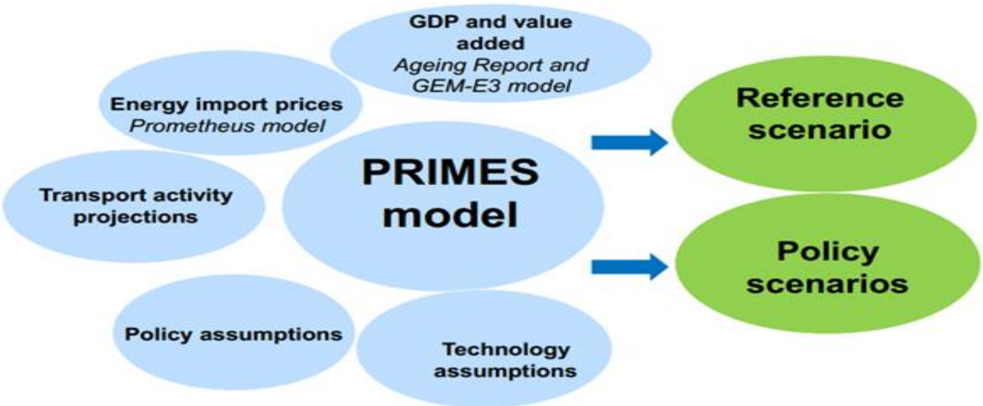

Figure 3.1: Diagram of PRIMES Model Structure (Daniel, 2014)

The technology attributes used in the PRIMES model are exogenous with both supply & demand side technologies considered. These technology attributes are reflected by parameters that are based on a variety of up to date reliable sources such as studies, expert judgement and existing databases (Daniel, 2014).

To account for future technological development certain assumptions are made for anticipated future development of technologies over the model run. For example, in the model, design regulations cause a reduction in cost of energy efficient devices and improved CO_2 standards for vehicles facilitate increased uptake of more efficient fossil fuelled vehicles and decent penetrations of electric vehicles. Other assumptions are made about the cost developments of technologies, such as reduced costs for wind and solar-photovoltaic generation but increased costs for nuclear generation following the nuclear disaster at Fukishima. Carbon capture and storage (CCS) is not anticipated in PRIMES to become commercially viable until after 2030 and even at that time for it to be deployed it will be reliant on the cost of carbon. These assumptions and others are further are detailed in (E3MLab/ICCS, 2014).

Figure 3.2[3] is a graphic illustrating the generation mix by Member State as in the Reference Scenario Results for 2030:

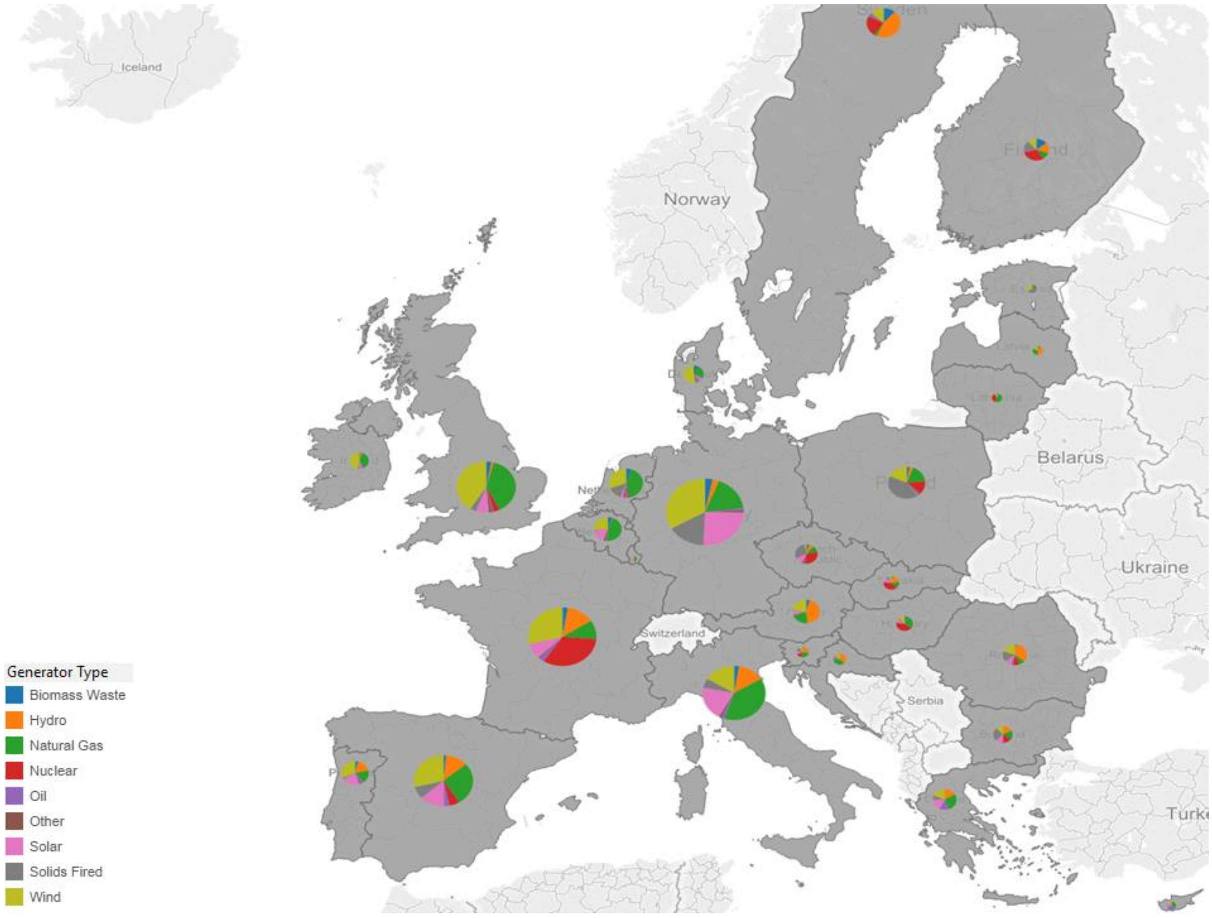

Figure 3.2: The generation mix by Member State in the 2030 Reference Scenario Results

[3] A numerical breakdown of all colour coded map figures developed in chapter 3 is available in Appendix A

3.3.3. Comparison of Models

Both PRIMES and PLEXOS models differ in focus and thus differ in representation of temporal and technical elements of the power sector. To properly compare both models, Table 3.2 is presented which details the differences between both models in the context of this work.

Table 3.2: Comparison of PRIMES and PLEXOS model characteristics

	PRIMES	PLEXOS
Model Class	Energy system model	Power system model
Sectoral focus	Rich in sectoral disaggregation	Isolated sectoral focus
Model Objective	To determine optimal technology pathway development for the Energy system	To perform detailed operational analysis of the power sector
Temporal Resolution	Low temporal resolution (Day/Night/Peak)	High temporal resolution (5min-1hr)
Time Horizon	Long time horizon (2050)	Short term operational focus <1 year
Technical Representation	Limited to broad operational constraints due to low time resolution	Very high technical detail allows for reserve modelling, hydro modelling, multi-stage stochastic unit commitment and determination of ramping costs & flexibility metrics

Table 3.2 provides context for the work at hand, by which value is added to large energy system model results through use of the dedicated power system model.

3.4. Methodology

3.4.1. Modelling Approach

The modelling approach used in this chapter is a soft-linking approach presented in Figure 3.3. This approach builds on approaches followed in previous papers (Deane et al., 2012) and (Deane et al., 2015a) by applying it to a 28 Member State multi-regional model[4]. It uses

[4] The Norwegian power system is also represented as defined by ENTSO-E for the year 2012 (ENTSO-E, 2012b) but the Swiss power system is simulated as a copper plate where interconnection between it and other EU countries is represented but not its installed generation capacity or demand.

highly detailed unit commitment and dispatch modelling of the electrical power system, derived from the energy system model results, to gain insights into its operational realisation and thus aid long term planning energy system planning.

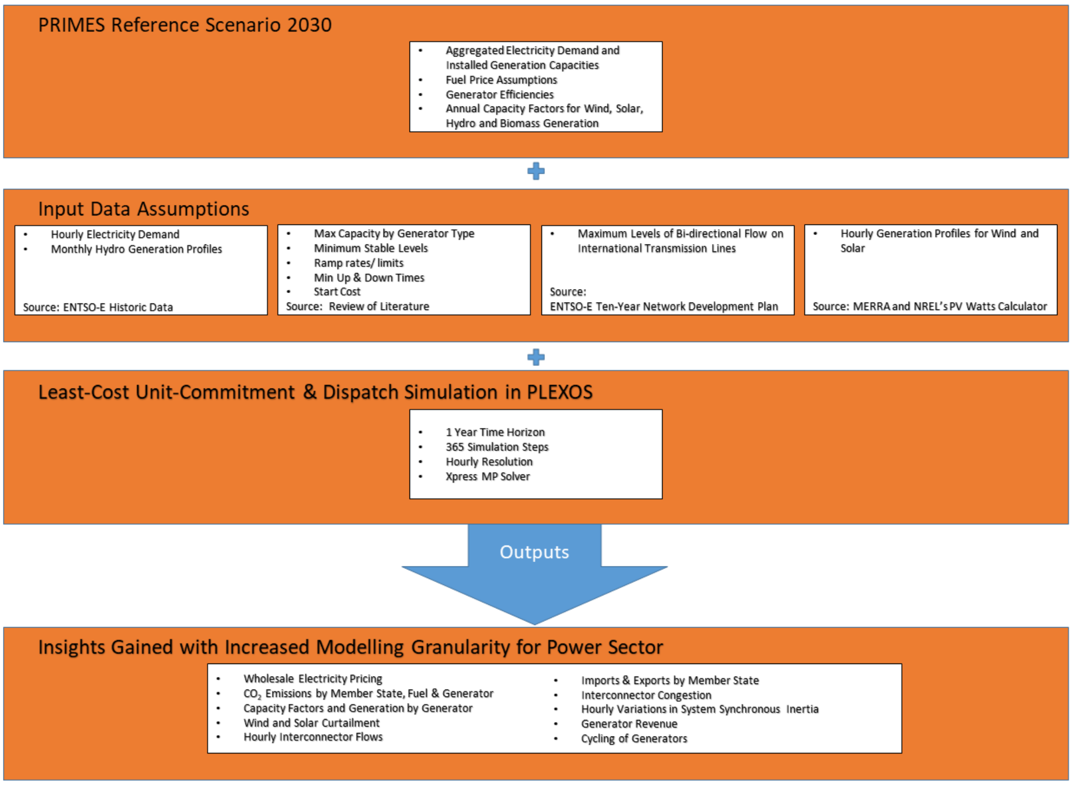

Figure 3.3: Flow diagram of the modelling approach

In PRIMES REF, results for the installed power generation capacities for each Member State are broken down into various modes of generation such as Hydro, Solids Fired, Oil Fired, Gas Fired, Biomass waste etc. The results issued from PRIMES are aggregate figures; therefore a challenge to the model's construction surrounded the disaggregation of these generation capacities. Deane et al highlighted that the development of national renewable energy action plans in individual countries can neglect the significant effects that cross border power flows have on market dynamics especially in the presence of geographically dispersed variable renewable generation sources such as wind and solar (Deane et al., 2015d). Aggregate generator portfolios were thus developed using standard generators with standard characteristics (max capacity, min stable factors, ramp rates, min up & down times, maintenance rates, forced outage rates, start costs etc), as opposed to developing portfolios as projected by individual Transmission System Operators, so to avoid the need to access both unit or manufacturer information that is commercially sensitive. A selection of these characteristics can be seen in Table 3.3 for thermal generators. These were determined after performing a review of available literature to ensure the values used were representative (Anderson and Fouad, 2008, ENERGINET, 2014, Commission for Regulation of Utilities Ireland, 2016, AEMO, 2012, Western Electricity Coordinating Council, 2016). Each disaggregated generation capacity was made up by numerous identical generators summing to the total capacity as split by fuel type in the PRIMES reference scenario results. For natural gas fired generation 10% of installed capacity was allocated as Open Cycle (OCGT) to reflect and capture the flexibility of these less efficient plants on the power system with the remainder of natural gas fired plants being modelled as Combined Cycle units (CCGT). Heat rates for the various types of power plant are defined on a Member State by Member State basis, in the PRIMES-REF scenario results.

Table 3.3: A selection of the standard generator characteristics used

Fuel Type	Capacity (MW)	Start Cost (€)	Min Stable Factor (%)	Ramp Rate (MW/min)
Biomass-waste fired	300	10000	30	30
Derived gasses	150	12000	40	30
Geothermal heat	70	3000	40	30
Hydro Lakes	150	0	0	30
Hydro Run of River	200	0	0	30
Hydrogen plants	300	5000	40	30
Natural gas CCGT	450	80000	40	30
Natural gas OCGT	100	10000	20	30
Nuclear energy	1200	120000	60	30
Oil fired	400	75000	40	30
Solids fired	300	80000	30	30

3.4.2. Interconnection

Net transfer capacities are limited for this work to Interconnection between Member States and no interregional transmission is considered below Member State level. The electricity network expansion is aligned with the latest 10 Year Development Plan from ENTSO-E, without making any judgement on the likelihood of certain projects materialising (ENTSO-E, 2016a).

Figure 3.4: Interconnection as modelled with the EU-28 Power System Model

3.4.3. Fuel and Carbon Pricing

Fuel prices used are from (European Commission, 2014) and are consistent across scenarios for each year and are shown in the Table 3.4 in terms of €2010 per barrel of oil equivalent (BOE). The CO_2 price used was €35 per Tonne (€2010).[5]

Table 3.4: Fuel prices used in study

Fuel prices	2030
Oil (in €2010 per BOE)	93
Gas (in €2010 per BOE)	65
Coal (in €2010 per BOE)	24

3.4.4. Demand

The results of the PRIMES model detail overall electrical demand at an annual level only and includes demand from all sectors of the economy and electric vehicles (Electric vehicles are 3.4% of all electricity demand and 2.6% of energy in transport under PRIMES REF conditions). The power system model constructed is at an hourly resolution, and for this reason needed an hourly electrical demand profile. This was done through using historic electricity demand profiles from ENTSOE (ENTSO-E, 2012a) for the EU28 in the year 2012 and scaling them to 2030 overall demand detailed in the PRIMES results by utilising an algorithm based on quadratic optimization within the PLEXOS software with a peak scaling of 1.1(Energy Exemplar, 2018b).

3.4.5. Wind Generation

Localised hourly wind profiles for each Member State of the EU28 were used within the model. Physical wind speeds at an 80m hub height we gathered for multiple locations in each of the 28 Member States through use of MERRA data (Rienecker et al., 2011). The multi turbine approach developed by Nørdgaard et al was used to account for the multi turbine and geographic spread nature of wind generation (Norgaard and Holttinen, 2004).

[5] An additional scenario with a CO_2 price of €40/tonne was also generated to compare with the PRIMES GHG40 scenario but the changes in simulation results were not significant.

3.4.6. Solar Generation

Localised hourly solar profiles for each Member State of the EU28 were created and used within the model. This was done through use of NREL's PVWatts® Calculator web application which determines the electricity production of photovoltaic systems based on a number of inputs regarding the system location and basic system design parameters (Dobos, 2013). The profiles created were then normalised with the generation capacity for each Member State as in the PRIMES-REF 2030 results.

3.4.7. Hydro Generation

Hydro generation is modelled as individual Member State monthly constraints via generation profiles provided by ENTSOE for each individual Member State of the EU28 and Norway. PLEXOS solves medium-term constraints like this in two stages which enables such constraints to be directly implemented in a shorter timeframe. This allows these monthly constraints to be decomposed to weekly and then hourly profiles in the optimisation process. In the first stage these monthly constraints are formulated directly in the simulation's linear programming formulation and in the second stage every trading period (hour) is modelled in detail.

3.4.8. Demand Response

Demand response was implemented by allowing 10% of peak demand in each Member State be shifted to optimise system performance at least cost over the course of the day.

3.4.9. Inertia

For this analysis, minimum levels of inertia were maintained above a certain level so as to limit the RoCoF to 0.75Hz/s on each synchronous grid in the European region (i.e. the Grids of Ireland (SEM), Great Britain (National Grid), the Baltic states, Nordic states (NORDEL) and the Central European grid (UCTE)). The grids of Malta and Cyprus were omitted for this constraint as for such small systems such a constraint isn't as reasonably practicable. In the model the inertia constraint is simulated by assigning levels of inertia to each individual generator based on levels from literature (Anderson and Fouad, 2008) and assigning minimum static levels of inertia be required on grid to mitigate the outage of the of the largest infeed in each system within the model as under the N-1 Criterion as exemplified by (Daly et al., 2015). The N-1 outage and corresponding minimum required inertia level used within this analysis for each region considered is displayed in Table 3.5. For the Irish SEM this N-1 incident was determined to be the 700MW HVDC interconnector to France, for Great Britain it was determined to be the 2GW HVDC interconnector to France, for the Baltic grid it was determined to be the 700MW NordBalt HVDC interconnector, for UCTE it was determined to be the 2GW HVDC interconnector between France and Spain, and for NORDEL it was determined to be the largest nuclear unit in Sweden within the model which was 1150 MW.

Table 3.5: The chosen N-1 contingency event for each synchronous grid analysed and the associated minimum inertia level assigned to limit RoCoF to 0.75 Hz/s

Synchronous Power Grid	N-1 Outage (MW)	Assigned Minimum Inertia (MWs)
UCTE	2000	66,667
NORDEL	1150	38,628
National Grid	2000	66,667
Baltic Grid	700	23,333
SEM	700	23,333

This was a custom built constraint that we developed specifically for this work within the PLEXOS software. Each of the five synchronous power systems within the PLEXOS model were constrained to maintain sufficient synchronous inertia to mitigate the outage of each of their respective N-1 outages. This is to say that the inertial contribution of all generators in each synchronous system at all times had to sum up to an amount that was equal or greater than this value. This constraint essentially placed a realistic limit on instantaneous penetration of non-synchronous power in each synchronous system. The impact of imposing these minimum levels of inertia is examined in this chapter identifying the inertia related challenges faced by certain regional grids in incorporating large shares of variable renewable generation.

Upon completion the PRIMES 2030 EU 28 Model consisted of over 2,200 generators, 22 Pumped Hydro Electrical Storage Units and 64 Interconnector Lines running at hourly resolution for the year 2030.

3.5. Results

This section presents and discusses a selection of results under a series of headings outlining the primary insights gained from this analysis. The main outputs are extracted and analysed with a particular focus on the impact of variable renewables on the operation of the European power system.

3.5.1. Wholesale Energy Prices

The wholesale energy price (electricity market price) here is derived based on the average hourly system marginal cost in each Member State over the course of the simulation based on the merit order. Scarcity pricing (a price cap in the event of unserved energy) was used in the model but filtered out in the determination of regional wholesale energy prices (New Zealand Electricity Authority, 2018). Uplift was enabled in the determination of pricing to ensure generators recovered fixed costs, this did not affect the optimal dispatch. However, this makes them not directly comparable to today's wholesale energy pricing. The prices reflected in the results of this work are higher than today's levels because of this uplift coupled with higher CO_2 and gas prices. As such these market prices reflect the true operation cost associated with achieving a reliable low carbon electricity system for Europe. The high penetration of variable renewable generation sources contributes to containing and even lowering the wholesale prices of electricity based on short run marginal cost alone by causing a shift in the merit order curve and substituting part of the generation of conventional thermal plants, which have higher marginal production costs.

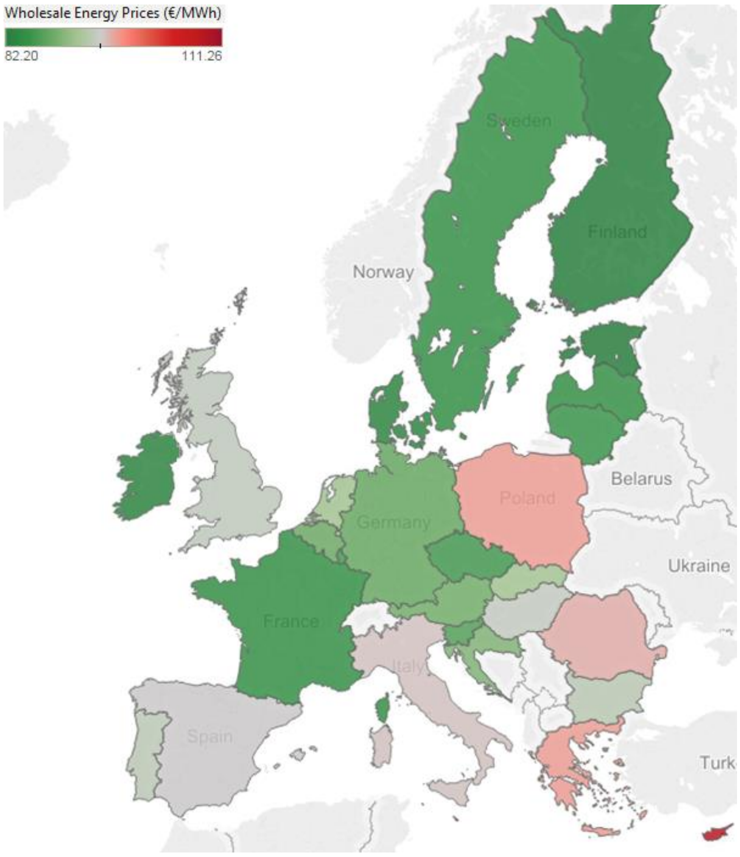

Figure 3.5: 2030 Wholesale Energy Prices by Member State

The wholesale energy price by Member State can be seen in Figure 3.5. This figure was generated for the year 2030 power system under the reference scenario results as simulated in the model constructed. These prices provide an insight into the effect of achieving renewable energy targets through use of a high proportion of variable renewable generation. A number of Member States can be seen to have the low wholesale energy prices, especially Ireland with a price of 84 €/MWh. In Ireland's case, this is directly attributable the high proportion of variable generation which is planned to be installed and presents concerns. This has a strong seasonal impact and tends to reduce prices in the winter months when wind speeds are high and demand is also highest. This reduces the need for higher marginal cost generators to meet peak demand and long term affects the revenue base of conventional thermal power generation.

Within the power sector in Europe today, current market prices are not sufficient to cover the fixed costs of all plants operating on the system, a situation that is expected to become more critical in particular due to the current overcapacity induced by the economic slowdown in recent years and the penetration of renewables, which predominantly have fixed costs (Deane et al., 2015c). The low capacity factors for natural gas fired plant, particularly in 2030 as can be seen in red (below 30% capacity factor) in Figure 3.6, suggest that natural gas fired plant may struggle to achieve sufficient financial remuneration in an energy only market in some Member States.

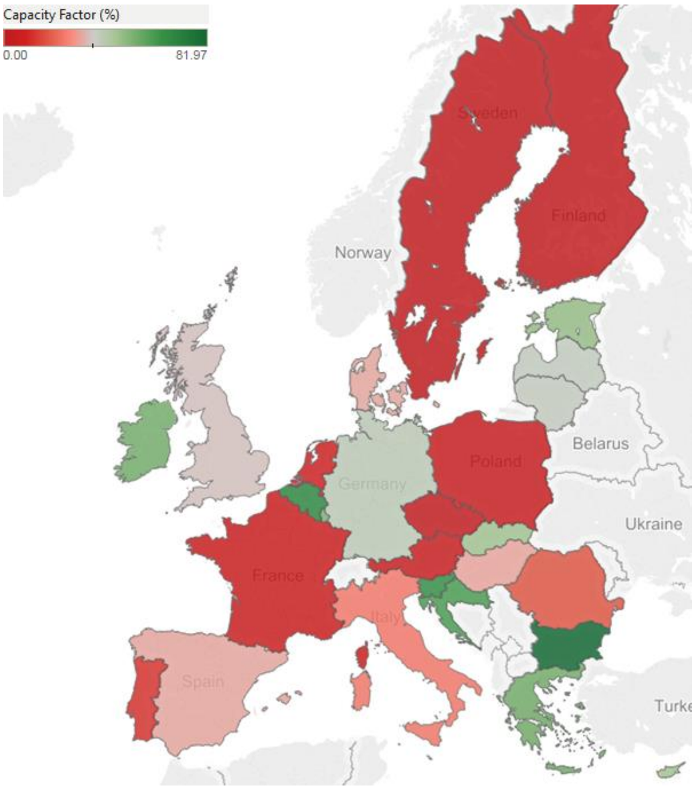

Figure 3.6: 2030 Natural Gas Fired Plant Capacity Factors by Member State

Figure 3.7 identifies the differences in capacity factors for Natural Gas generation between the 2030 PRIMES Reference scenario results and the results of the UCED scenario model. It is clear that the capacity factors differ substantially across the EU-28 between both models, at an average absolute difference of 18%.

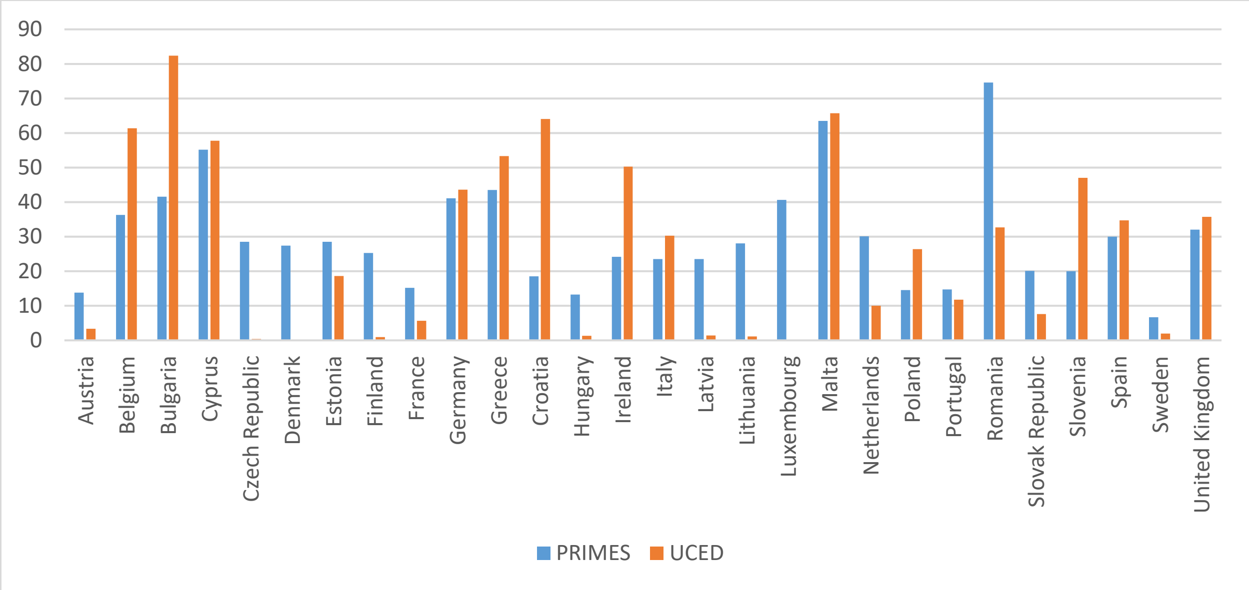

Figure 3.7: 2030 PRIMES REF and UCED scenario Natural Gas Fired Plant Capacity Factors by Member State

3.5.2. Variable Renewable Curtailment

Figure 3.8: Variable Renewable Curtailment by Member State

Variable renewable curtailment, in this case curtailment of wind onshore, wind offshore and solar generation, is one metric by which power system flexibility can be measured. Here curtailment is defined as the variable renewable power that cannot be used or stored and must be dumped due to operational constraints and/or insufficient demand. The high penetration of variable renewables in the 2030 PRIMES REF scenario indicate that this merits consideration, a factor which is not captured explicitly in PRIMES modelling. The ability of this approach to capture generation and interconnector flows at high temporal and technical resolution is critical in capturing the times & frequency at which Member States cannot utilise their full renewable generation and indeed export their surplus generation. Figure 3.8 is a graphic displaying the variable renewable curtailment for Member States in the model. Isolated power systems such as those of Malta and Cyprus have high amounts of curtailment by virtue of their isolation. Another Member State however that encounters curtailment is Ireland who are significantly better interconnected, thus perhaps raising the possibility to investigate remedial options such as storage and greater interconnection, or, indeed, novel network configurations for deployment of offshore renewables that can dovetail increased penetration of renewables with increased interconnection that facilitates their better integration (Houghton et al., 2016).

Maintaining minimum system inertia levels to maintain frequency are binding constraints that increase the levels of curtailment in the case of Ireland due to its relative isolation and high penetration on onshore wind generation. However, the scenario being analysed here is the reference scenario which is similar to a business as usual scenario. Any further measures to increase the penetration of variable renewables in policy scenarios will see increases in the curtailment of variable renewable generation across the EU.

In addition to the aforementioned remedial measures of storage, increased interconnection and novel network configurations, VRE curtailment is a factor in particular that could be mitigated by operational flexibility measures such as greater integration of the electricity sector with other sectors, such as thermal or transport sectors, in the form of demand response that could modify their demand to purchase the electricity cheaply that would otherwise have been curtailed.

3.5.3. Interconnector Congestion

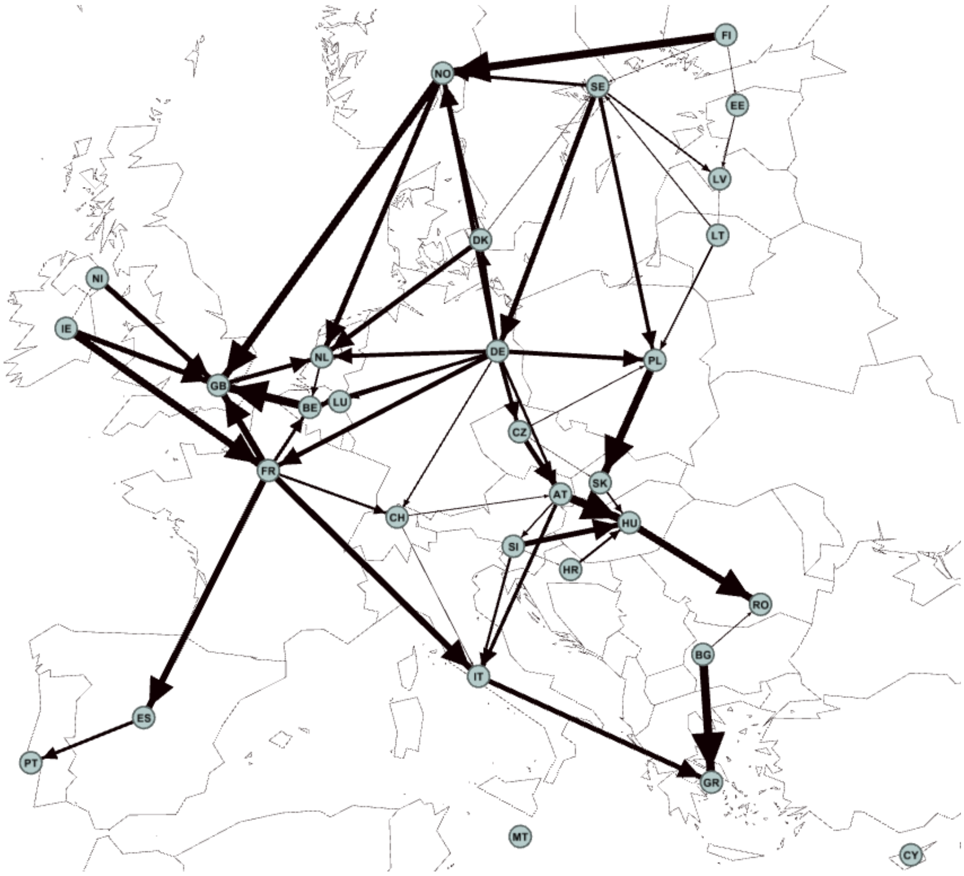

Figure 3.9: 2030 Interconnector Congestion by Member State

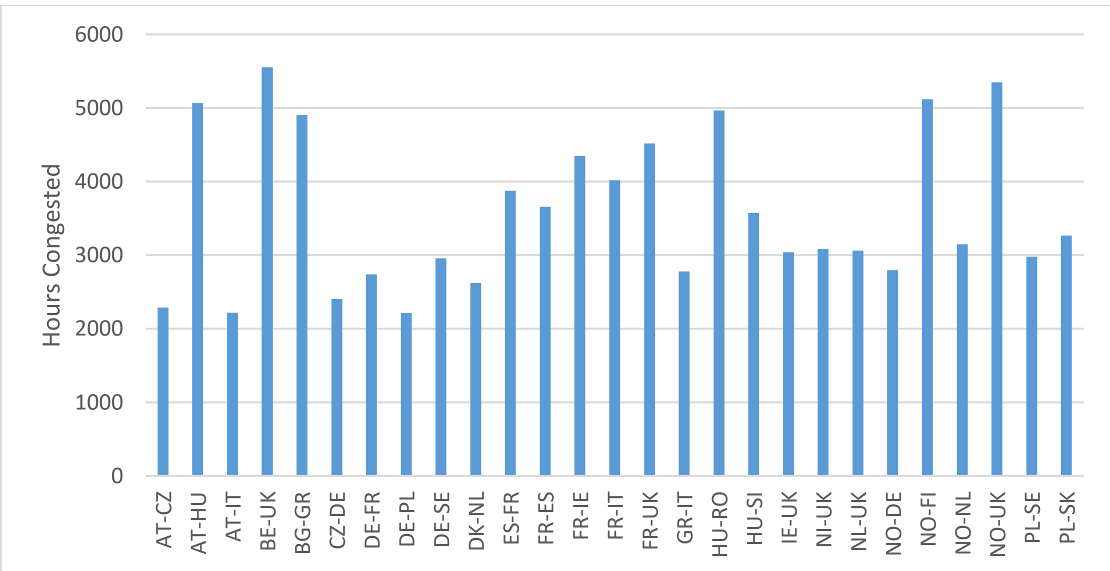

Figure 3.10: 2030 Interconnector Congestion by Member State

Limited interconnection capacity can mean the benefits coming from renewable energy sources and potential electricity trade are lost. It is not easy to identify optimum levels of interconnection (EWEA, 2009). Congestion here is defined as the hours that a line is operating at maximum capacity. On average interconnection in 2030 was congested for

24% of the year. In Figure 3.9 and Figure 3.10 the number of hours congested can be seen for the interconnection lines in the model simulation of 2030 which experienced high amounts of congestion (in excess of 2000 hours). Congestion on interconnection lines limits the efficient movement of electricity particularly in Central and Eastern Europe lines which raises concerns over the flexibility of the power systems within these Member States, highlighting the need for increased interconnection. Increased amounts of variable renewables coming online up to 2030 will put pressure on interconnection levels so that supply may meet demand to avoid curtailment. More ambitious policy scenarios with greater amounts of variable renewables would encounter even more congestion. The congestion identified on interconnectors in this study cannot all be appropriated to the increased penetration of renewables, it may also indicate pre-existing infrastructural inadequacy within the system.

3.5.4. Impact of Demand Response

Demand response allowed the shifting of portions of peak demand to times when it was cheaper to serve this load, thus leading to a decrease in total system operation costs of 1%. Demand response also reduced overall interconnector flow by 3.9% which in turn reduced the wheeling costs associated with international flow of electricity. However, average number of hours for which lines were congested increased by 0.8% which indicates that although overall flow is reduced, line capacity continues to restrict and limit the efficient flow of electricity. This cost optimal load shifting also led to curtailment reduction, although the binding minimum levels of inertia and limited interconnection meant this potential remained limited for Ireland where curtailment remained above 10%. Under the implementation of demand response, overall CO_2 emissions increased by 3.2% due to demand shifting allowing less flexible coal generation to be used instead of flexible natural gas CCGTs to meet a flatter demand profile. Interestingly, this aligns with findings in (Houghton et al., 2016) that showed how another system flexibility measure, increased interconnection, can lead to increased emissions also. Thus, analysis of demand response and other renewable energy integration measures merit further study and an extensive sensitivity analysis to better define their impacts and benefits as flexibility measures under a variety of modelling assumptions.

3.5.5. Impact of Maintenance of Sufficient Levels of Grid Inertia

The maintenance of sufficient levels of grid inertia was analysed with a focus on its impacts on the operation of the various synchronous grids of Europe. In order to maintain sufficient inertia on the power system at times of high penetration of variable renewable generation it is necessary in the model for other modes of generation to pick up the slack and remain online to provide inertia.

3.5.5.1. Continental European Grid (UCTE)

The impact of this maintenance of sufficient inertia is negligible for synchronously interconnected Member States on the central European grid due to the utilisation of inertia sharing between numerous of Member States. The minimum inertia requirement in this model to offset an outage of 2GW for the central European grid is 66,667 MWs. The inertia levels of the central European grid do not come close to this minimum level of 66,667 MWs with a minimum of 1,168,000 MWs for 2030.

3.5.5.2. Nordic Grid (NORDEL)

Similarly, under the PRIMES 2030 reference scenario conditions, NORDEL does not find the imposition of an inertia constraint binding. The inertia constraint of 38,600MWs to offset an outage of 1148MW is comfortably met with the minimum inertia in 2030 in excess of 200,000MWs. This owes primarily to the high installed capacity and generation of Hydro and Nuclear sources in particular.

3.5.5.3. National Grid of Great Britain

In Great Britain, the high penetrations of variable renewable generation sources, wind in particular, lead to a very variable inertia level on grid, as can be seen in Figure 3.11, which does bind at the 66,667 MWs minimum to offset a 2GW outage. The composition of generation does not change significantly while constrained, the most effected generation source was Natural Gas CCGT which sees a 39% drop in the number of units started in 2030 to 54 starts per unit which remain online to provide inertia and a 2% increase in total system generation costs. The relationship between the online inertia and wind generation is apparent in Figure 3.11, during windy months of winter the inertia levels are much more variable while during the less windy months of summer the inertia levels are much more stable. Whilst curtailment of variable renewable generation levels are minimal, the levels of curtailment would increase with increased penetrations of variable renewable generation under policy scenario conditions resulting in a decrease in the capacity credit of wind.

3.5.5.4. Baltic Grid

The impact is more notable in the case of the Baltic grid because the minimum inertia level of 23,333 MWs is a binding constraint to offset an outage of 700MW, this can be seen in Figure 3.11. This leads to the requirement of increased capacity factors in thermal generation units with Natural Gas CCGT capacity factors increasing in this region by 9% to an average capacity factor of 13%. Increased synchronous interconnection would alleviate such problems associated with maintenance of inertia within the Baltic States and enable wider inertia sharing not currently possible via HVDC interconnection.

3.5.5.5. Irish Grid (SEM)

The current minimum inertia level as defined by the transmission system operator of Ireland is 20,000 MWs to limit the RoCoF to 0.5Hz/s (Eirgrid, 2017) for an outage of 500MW. For this analysis the minimum inertia level was set as 23,333 MWs to offset an outage of 700MW and limit RoCoF to 0.75 Hz/s in anticipation of improved generator tolerance by 2030. The seasonal relationship between variability of wind generation and system inertia is very similar to that of Great Britain, visible in Figure 3.11. Given Ireland's very high penetration of variable renewable generation and synchronously interconnected isolation, this constraint is quite binding and leads to significant implications for the Irish power system. As detailed previously, the high curtailment rate of variable renewable generation is a direct implication being in excess of 11%. Greater penetrations of renewable generation will lead to greater curtailment levels and reduced capacity credit of variable renewable generation.

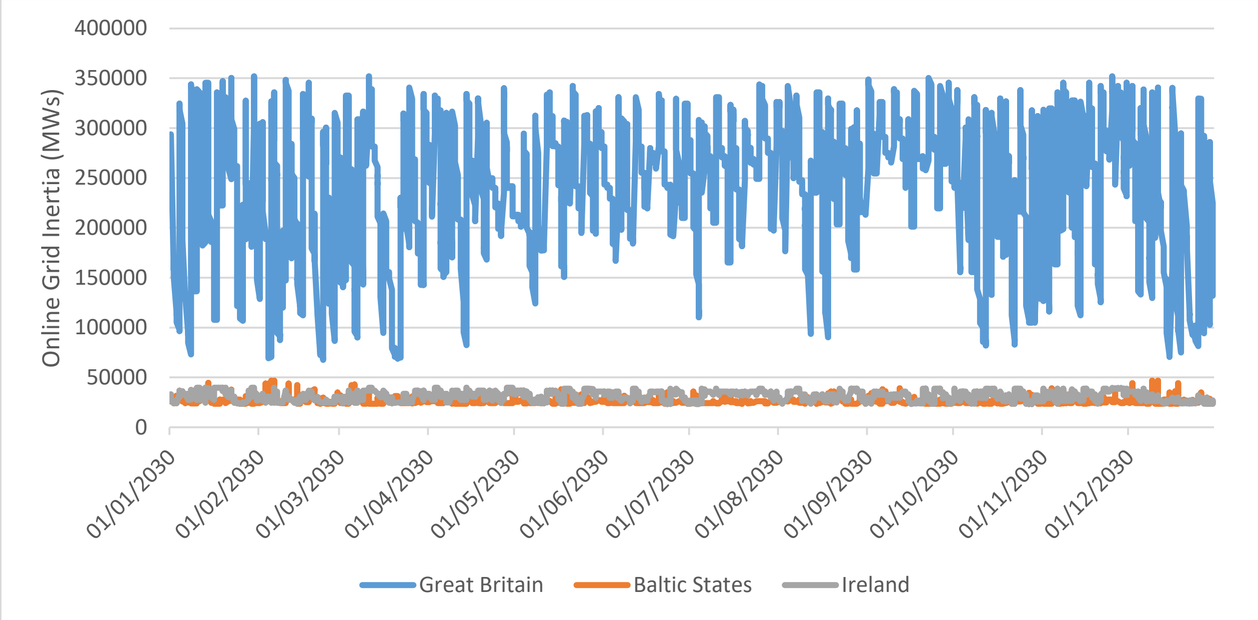

Figure 3.11: Variation of online inertia over year for synchronous grids of Great Britain, the Baltic States and Ireland.

3.6. Conclusions

Current long term energy planning and energy policy is largely informed by long term models that can struggle to capture sufficiently the operational integration of many renewable technologies for the power sector. This can often lead to misleading signals regarding the cost and difficulty of achieving carbon reduction targets, thus leading to sub optimal planning. This chapter demonstrates a multi model methodological framework to address this which enables analysis of the robustness and technical appropriateness of the power sector results for a target year of the PRIMES energy system model which has been used to directly inform European energy policy development.

The specific value added by this chapter is that it enables detailed operational analysis of the power sector not possible in a single long term energy system model approach. This additional modelling captures elements that are not represented in the PRIMES energy system model. This value added allows for the assessment of the impact of high penetrations of variable renewable technologies on the power flows across the European power system and their impact on the flexibility of the system in terms of pricing, interconnector congestion, capacity factor of fossil fuel generation, curtailment of variable renewable generation and provision of synchronous inertia. In the least cost dispatch simulation variable renewable generation formed 24.2% of total generation whereas PRIMES REF long term model results this was 26.6% of generation, indicating an overestimation of the European integration potential of variable renewable power in

PRIMES by 2.4%. To achieve greater shares of variable renew able power generation such as those of over 80% as discussed in (Connolly et al., 2016) will require very substantial increase in system flexibility and sectoral integration given the high congestion and curtailment identified in this chapter. A key conclusion from this work is that for the assessment long term energy system planning a suite of models are best suited to informing long term planning of the energy system because it allows the strengths of each model to be exploited to better analyse the results of the other.

The impact of increased levels of variable renewable on conventional generation, especially natural gas fired CCGT plants, is quite profound once the capacity factor for this mode of generation is taken into account. This could cause concerns in regard to incentivising investment for conventional fossil fuelled generation in an energy only market which are of great importance from a generation adequacy and security perspective given their roles in frequency and voltage stability maintenance (Viawan, 2008).

The capture of variable renewable curtailment and interconnector congestion enable the determination of the power system flexibility. Implicit in this is the measurement of the ability of their power systems to absorb the variable renewables. These elements can be analysed within this multi model methodology, but are not at all captured in the PRIMES energy system model which can lead to overly optimistic results. They are important factors in the projection of power system development especially in cases such as PRIMES REF where there are high penetrations of variable renewables. The levels of curtailment experienced by Member States whilst being low (apart from certain outliers like Ireland, Malta, Cyprus and Portugal which reach levels of up to 11%) are still significant considering that this is a reference scenario that does not account for the implementation of policy measure post Spring 2012. Policy scenarios which impose greater amounts of variable renewable generation would encounter greater levels of curtailment. This work also highlighted interconnector congestion which on a European level was 24% on average, especially limiting the efficient movement of electricity particularly in Central and Eastern Europe lines. The heavy congestion, given the increasingly variable nature of power generation within the EU, highlights the need for increased interconnection especially in eastern and central European Member States under the reference scenario conditions.

The increasingly variable nature of power generation in Europe has clear implications for the reduction of the inertia of its power system and impacts on the frequency stability of the system. Although not a concern for the majority of European Member States, increased penetrations of variable renewable generation would increase curtailment of renewable energy and generation costs. Certain Member States are already experiencing such issues today such as Ireland (Eirgrid, 2018) and Great Britain (National Grid, 2016). In this chapter, Ireland is the only synchronous power system which experiences very high levels of VRE curtailment under these conditions in 2030 due to maintenance of inertia levels. Even though minimum inertia levels are shown to be binding on system operation in 2030 for Great Britain, in this work they did not yet lead to high levels of curtailment. Great Britain and the Baltic states would likely start to encounter such issues also under increased penetrations of variable renewable generation. The distribution of inertia by Member State within this large system is not considered but could be a significant issue for a European system with high penetrations of variable renewable generation.

The benefits of power system flexibility in addressing certain issues highlighted by this work cannot be underestimated. Increased deployment of storages, demand response and better integration of electricity, thermal and transport sectors will play a strong role in the decarbonisation of the energy system (Connolly et al., 2016). This work showed that demand response, while effective in reducing total generation costs and reducing curtailment, can lead to increased emissions due to demand shifting allowing less flexible coal generation to be used instead of flexible natural gas CCGTs to meet a flatter demand profile. This work also showed that demand response can have limited impact in terms of reducing interconnector congestion when used in the sole context of minimising overall generation cost. As such, demand response and other flexibility measures merit further study in the context of European energy policy development whilst accounting for interconnector flows.

Future work is recommended to analyse aspects surrounding how better integration of electricity, thermal and transport sectors, and application of flexibility measures such as storage and demand response that will aid the move toward a European low carbon energy system. It is also recommended to investigate in greater depth the nature of inertia provision under PRIMES reference scenario conditions regarding the distribution of inertia by Member State within this large system.

Chapter 4: Consumption-Based Approach to RES-E Quantification: Insights from a Pan-European Case Study

4.1. Abstract

The nexus between renewable electricity (RES-E) generation and interconnection is likely to play a large part in future de-carbonised power systems. This chapter examines whether RES-E shares should be measured based on consumption rather than production with a European case study presented for the year 2030. The case study demonstrates the volume and scale of RES-E transfers and shows how countries have differing RES-E shares when comparing those derived based on the traditional production-based approach to the alternative. The proposed consumption-based approach accounts for RES-E being imported and exported on an hourly basis across 30 European countries and highlights concerns regarding uncoordinated support mechanisms, price distortions and cost inequality. These concerns are caused by cross-border subsidisation of electricity and this work proposes that an agency be appointed to administer regional RES-E affairs. This agency would accurately quantify RES-E shares and remunerate producers from the country that consumed their electricity instead of where it has been produced – policy would be enhanced by enabling more equitable and optimal electricity decarbonisation.[1]

[1] Published as: GAFFNEY, F., DEANE, J. P., COLLINS, S. & Ó GALLACHÓIR, B. 2018. Consumption-based approach to RES-E quantification: Insights from a Pan-European case study. Energy Policy, 112, 291-300.

4.2. Introduction

Globally, power sector portfolios are undergoing a technology transformation with the ambition of achieving long-term carbon-neutrality. The Paris agreement of 2015, signed by 195 countries, is a significant driver of technological change as a concerted effort is needed to limit greenhouse gas emissions in order to keep global temperatures 'well below' 2°C above pre-industrial levels (Rogelj et al., 2016). The European Union's (EU) Emissions Trading Scheme (ETS) as well as various climate and energy packages are policy instruments that promote the decarbonisation of the energy system through incentivising emissions reduction, increasing energy efficiency and increased deployment of renewables. Higher levels of variable renewable electricity (RES-E) can pose challenges for power system operation as they produce non-synchronous and non-dispatchable electricity (i.e. wind, solar, wave, tidal) (Schaber et al., 2012). These challenges can be mitigated to a certain extend by interconnection to neighbouring systems (Denny et al., 2010, Booz & Co. et al., 2013). Furthermore, as renewable generation grows, there is an increasing likelihood that RES-E may be exported to neighbouring countries during periods of excess power. While the authors are cognisant that '*an electron is an electron'* no matter how it is generated, it is also recognised that RES-E targets in many regions do, in fact, differentiate between electrons – by source.

EU Member States for example, must achieve renewable electricity targets based on "*the quantity of electricity produced in a Member State from renewable energy sources*" as a proportion of Gross Final Consumption (GFC),[1] as stated in Article 5(3) of the Renewable Energy Directive (2009/28/EC)(European Parliament and Council, 2009a). Applying a production-based approach is sensible in an isolated, closed system where electricity production must equal consumption; meaning all renewable electricity is consumed domestically.

[1]The GFC of electricity is defined as: "Gross electricity production from all energy sources (actual production, no normalisation for hydro and wind), excluding the production of electricity in pumped storage units from water that has previously been pumped uphill; plus total imports of electricity; minus total exports of electricity." (Eurostat, 2016b)

However, interconnector transfers and planned increases in capacity[2] are playing an increasingly important role in today's European power system, i.e. making it easier to share renewable electricity surpluses and improving the operational control of a system. Equally a patchwork of varying national support schemes for renewable generation has led to situations where renewables are built where support is the strongest, rather than where the most cost-effective. Consequently, transfers of renewable electricity across interconnectors can present situations where the costs of renewable electricity are subsidised in one country and consumed in another. This therefore begs the question whether a consumption-based accounting approach to quantifying renewable electricity, which considers these transfers, should be used?

The Renewable Energy Directive already acknowledges that it is appropriate to facilitate the consumption of energy in one Member State which has been produced from renewable sources in another in order to meet defined targets in a cost-efficient manner. The directive proposes flexibility measures in the form of statistical transfer and joint projects between Member States to facilitate this. However, Member States have so far not engaged in these schemes with just two exceptions: Sweden and Norway (non-EU Member State); and Denmark and Germany (IEA, 2016b). Uncoordinated financial support schemes have the potential to cause price distortions between neighbouring countries which can lead to electricity transfers that do not provide societal gain and potentially cause cost inequalities as RES-E supported in one country is consumed in another, raising questions around 'who pays the difference between the market price and support scheme strike price?' Viewing renewable generation from a consumption-based standpoint delivers a different perspective on the intricacies involved in electricity generation and transmission. Identifying the movement of RES-E between countries opens 'Pandora's box' in terms of accounting for RES-E shares, costs inequalities associated with transferred RES-E and potential price distortions but it also sheds light on whether the current production-based approach is 'fit for purpose' in a future de-carbonised electricity sector.

[2] Interconnection capacity targets for Member States are 10% and 15% of installed electricity production capacity by 2020 and 2030 respectively. (European Commission, 2017b)

In this chapter, a consumption-based approach for quantifying a country's RES-E share is proposed and implications for renewable support schemes are discussed. The methodology is based on the concept of measuring the RES-E that is actually consumed within a country's boundary rather than what is produced. Accounting for interconnector inflows and outflows is a fundamental part of the methodology that provides the key difference between this and a traditional 'production-based' approach. The proposed consumption-based approach is demonstrated using the European internal market for electricity (hereafter; EU Target Model) as a case study for a single year. Note that under the Renewable Energy Directive for example, consumption-based measurement of renewables is used for the transport and heating & cooling sectors.

As in chapter 3, using PLEXOS Integrated Energy Model, a European electricity model for 2030 is created based on the 2016 European Commission's Reference Scenario (Capros et al., 2016) for the year 2030.[3] Once simulated, the results are post-processed to determine the country[4] where RES-E is produced and more importantly, where it is consumed, on an hourly basis. In doing so, issues associated with mass RES-E transfer across Europe are captured, such as uncoordinated support schemes, price distortions and cross-border subsidisation. These insights allow an in-depth discussion on the challenges and the institutional structures that need to be addressed to achieve a low carbon power system.

While many publications concentrate on topics such as the production-based versus consumption-based quantification question (Fan et al., 2016, Simas et al., 2017, Shao et al., 2016, Wiedmann, 2009, Larsen and Hertwich, 2009, Peters, 2008, Ji et al., 2016), the facilitation of RES-E in power systems (Daly et al., 2015, McGarrigle et al., 2013, Cleary et al., 2016, Fraunhofer IWES, 2015, Gaffney et al., 2017b, EirGrid & SONI, 2011, EirGrid & SONI, 2010, Henriot et al., 2013, Collins et al., 2017a, Deane et al., 2015d) and/or the importance of border trade (Bahar and Sauvage, 2013, EURELECTRIC, 2016, Fraunhofer IWES, 2015, EirGrid & SONI, 2010, Booz & Co. et al., 2013, Denny et al., 2010, IEA, 2016a) regarding their respective place in a future decarbonised electricity system, few

[3] The EU Reference scenario is derived from the reference scenario of the PRIMES model as was the basis for the model developed in chapter 3.
[4] "Country" is preferred over "Member State" as not all countries in the model are part of the European Union, i.e. Norway and Switzerland.

publications focus on the quantification requirements when both RES-E integration and cross border trade are taken together. Ji et al. (2016) highlight a concern surrounding electricity traded between power systems and the characteristics associated with the transfer. Focusing on the greenhouse gas emissions aspect of traded electricity, Ji et al. (2016) outline a high-level proposal to account for both direct and in-direct emissions that widens the boundary under consideration when addressing the concern.

Building upon Ji et al.'s concept of 'broadening the boundary under consideration,' we present a test case that highlights: 1) the short-comings of a production-based approach in interconnected systems with high levels of renewables; 2) challenges and potential solutions for the European internal market in 2030; and 3) concerns over pecuniary externalities caused by cross-border subsidisation and uncoordinated support schemes which can lead to issues surrounding effects on investment signals and long-term security of electricity supply problems.

The chapter is structured as follows. Section 4.3 outlines the methodological approach and assumptions used during the analytical phase of the chapter. Section 4.4 overviews the main results from the analysis, while Section 4.5 discusses various potential impacts associated with the proposal along with considerations related to its implementation. Section 4.6 concludes the chapter with some final remarks.

In an effort to promote transparency, the PLEXOS model and the excel tool used to calculate renewable electricity flows, along with all associated data have been made freely available online for academic research at: https://#www.dropbox.com/sh/m6pik1iql3ddpuj/AABYdHHk4_43WpGoSFNx329Aa?dl=0

4.3. Methodology

The methodology applied combines a soft-linking approach between energy system and power system models, as applied in chapter 3, with a post-processing phase to ascertain the volume of RES-E that is both produced and consumed in each country included in the analysis. First, the European Commission's Reference Scenario is soft-linked to a power system model comprising of 30 European countries (EU-28 Member States,[5] Norway and Switzerland) focusing on the year 2030. Post-processing is carried out on an hourly basis, in line with the EU Target Model day-ahead market scheduling algorithm known as the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA)(N-Side, 2016). This analytical phase will address the phenomenon known as 'wheeling', where electricity may be traded through one country to access another, based on wholesale market price differentials. Through analysis of the data it is possible to separate the share of interconnector flows subject to 'wheeling' compared to that derived directly from the country in question.

4.3.1. Power System Simulation

As discussed in section 3.3.1, PLEXOS Integrated Energy Model (PLEXOS) is a power system modelling platform used for power and gas market modelling. The software is a unit commitment and economic dispatch modelling tool that optimises at least cost the operation of the electricity system over the simulation period at high technical and temporal resolution whilst respecting operational constraints. Version 7.4 (R02) of PLEXOS was operated on a Dell Inspiron CN55905 laptop with a 6th Generation Intel® Core i7-6500U Processor. The MOSEK solver was used to simulate the model with Rounded Relaxation unit commitment applying a 0.01% relative gap and 6-hour look-ahead. Using hourly dispatch, in line with the EU Target Model day-ahead market scheduling platform, 365 days were simulated to replicate 2030, taking 1.5 hours to complete.

4.3.1.1. Scenario Description

The installed power generation capacities for the EU-28 Member States were outlined in the European Commission's Reference Scenario by generation class, for example; Hydro,

[5] At the time of writing, the United Kingdom remains a constituent of the European Union.

Oil, Gas, Solids, Biomass/Waste, et cetera. The portfolios were disaggregated into individual power plant types by fuel class and assigned standard technical characteristics as shown in Table 3.3 in chapter 3. This analysis used the same modelling approach as chapter 3 that was first outlined in (Deane et al., 2012). Assumptions for the Swiss and Norwegian power systems were based on (ENTSO-E, 2016b)– Vision 1[6] . Fuel and CO_2 pricing is as shown in Table 4.1 and are as per the EU Reference Scenario 2016 (European Commission, 2016b).

Table 4.1: Fuel and CO_2 price assumptions

Fuel Type / CO_2	2030
Oil (€2010 per BOE)	€90
Gas (€2010 per BOE)	€52
Coal (€2010 per BOE)	€18
CO_2 - ETS (€2010 per Tonne)	€40

The model is simulated as a closed loop comprising of 30 European countries and 58 interconnectors and overall regional generation must meet regional load in each hour simulated. Therefore, when all hourly interconnector flows (exports and imports) are summed, the result must be zero (given all transmission and distribution transfer losses, including interconnector losses, are endogenous in the demand profiles), as shown in Eq. (1).

$$0 = \sum_{i=1}^{58}(IC_i) \qquad (1)$$

where *i* represents interconnectors and *IC* is the flow of electricity on an interconnector. *IC* flow is positive for exports and negative for imports.

4.3.1.1.1. Demand Profiles

Hourly resolution demand curves were attained from historic ENTSO-E data (ENTSO-E, 2012a) and linearly scaled to the overall demand estimates outlined in the European Commission's Reference Scenario. The European Commission's Reference Scenario

[6] Vision 1 was chosen over the other scenarios represented as it was the most conservative 2030 option and, therefore, most closely aligned with the European Commission's Reference Scenario.

demand estimates are inclusive of all transmission and distribution transfer losses (including international interconnector losses).

4.3.1.1.2. Wind, Solar and Hydro Profiles

Hourly generation profiles for wind power were sourced from (Gonzalez-Aparicio et al., 2016). Solar profiles were created from NREL's PVWatts® calculator which estimated the solar radiance from assumptions around system location and basic system design parameters for each country (Dobos, 2013). Hydro profiles are decomposed from monthly generation constraints provided by (ENTSO-E, 2012a)to weekly and hourly profiles in the optimisation algorithm function in PLEXOS.

Pumped hydro energy storage is not simulated in this model for the reason being that it increases simulation time significantly but more importantly because under Article 5(3) of the Renewable Energy Directive *"renewable energy sources shall be calculated as the quantity of electricity produced in a Member State from renewable energy sources, excluding the production of electricity in pumped storage units from water that has previously been pumped uphill."(European Parliament and Council, 2009a)*.

4.3.1.1.3. Interconnection

The interconnection capacities between countries represented in the model are based on projections from the (ENTSO-E, 2016a) *'Ten Year Network Development Plan 2016'* publication, see Figure 4.1.[7] Interconnection is limited to net transfers between countries and excludes interregional transfers in line with the EU day-ahead market schedule dispatch clearing algorithm, EUPHEMIA. Given that interconnector losses were included in the electricity demand profiles used already they were not represented as losses in the dispatch again but to account for their costs in terms of the economic dispatch, wheeling charges of €4/MWh were applied to the model for all interconnector lines.

[7] Malta is the only electrically isolated country represented in the model.

Figure 4.1: High-level view of interconnection capacity represented in the PLEXOS model[8]

4.3.2. Post-Processing

Post-processing is required to identify the RES-E flow across Europe's interconnectors for each hour of a given year. Due to the complexity associated with tracing wheeled exports to their source(s), this approach employs a multi-step process to continually trace wheeled exports until all RES-E transfer is accounted for. The foundation of this approach lies with the identification of the true source(s) of wheeled exports in each hour. Once known, the exported electricity is checked for any RES-E content. While in most cases no RES-E content exists, when it does however, it is possible to trace the energy to its point of consumption purely based on the economic dispatch of generation portfolios and the merit-order approach (Sensfuß et al., 2008, Sáenz de Miera et al., 2008).

This approach functions on the assumption that all country-specific electricity markets within the model employ an economic dispatch approach, therefore RES-E is consumed locally to meet domestic load before any renewable exports can occur. This is supported by the requirement under Article 16 of Renewable Energy Directive for transmission system operators to comply with their duty to minimise curtailment of renewable electricity and

[8] Greece is also electrically connected to Cyprus. This interconnector is excluded from Figure 4.1 to maintain granularity around areas with the highest interconnection density.

based on the knowledge that a high share of EU RES-E generation receive power purchase agreements through government backed support schemes, as demonstrated by (RES Legal, 2017). Therefore RES-E can bid in low, zero or negative bid prices to the energy market to reduce dispatch exposure.[9] Furthermore, when RES-E flow has been identified as travelling between countries the same principle is used in the importing country in terms of economic dispatch. In other words, RES-E is only exported if the combined domestic RES-E and imported RES-E (if applicable) exceeds domestic load.

4.3.2.1. Components of Interconnector Flow

In this methodological approach, electricity transferred via interconnection is considered a combination of two components. The electricity is either a direct product of the country where the interconnector originates or an indirect product which is derived from another location and passes through one country to another, also referred to as 'wheeling electricity'. Henceforth the first is referred to as "Domestic Exports" and the second is referred to as "Wheeled Exports." Domestic Exports (DE) occur when domestic generation exceeds domestic load, causing an export of electricity directly associated with the country in question. Wheeled Exports (WE) are equal to interconnector flow net of Domestic Exports, see Eq. (2).

$$IC_i = \sum_{i=1}^{58}(DE_i + WE_i) \qquad (2)$$

where,

- DE = Domestic Generation – Domestic Load
- WE = Interconnector Flow – Domestic Exports (if Domestic Exports >0)

else,

- WE = Interconnector Flow

where *i* represents interconnectors.

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[9] RES-E generation has the advantage of priority dispatch under the Renewable Energy Directive (2009/28/EC). This may not be in the case in 2030 as outlined in the draft directive on the Internal Electricity Market. (European Commission, 2016e)

4.3.2.2. Calculating the RES-E Share of Interconnector Flows

To measure the RES-E share of Wheeled Exports across an interconnector, the true source of the electricity must first be determined by tracing interconnection flows back to their origin. In doing so, what is actually identified as the source of Wheeled Exports is in fact a country that is not importing electricity at all but is exporting RES-E.[10] Therefore, to identify the source(s) of wheeled electricity in a given hour a country must export electricity and not import, as shown in Eq. (3). This essentially means that we identify countries where no interconnector is importing and all interconnectors that are in use are exporting. The RES-E share of electricity transfer is then assessed and if applicable, quantified using Eq. (4). Eq. (4) states that RES-E generation *must* first exceed domestic load for any renewable export to occur. If RES-E export occurs, its percentage of RES-E in domestic exports is determined as shown in Eq. (4). The percentage of RES-E flows in these domestic exports is assumed to be uniform across all exporting lines. Finally, the results are tabulated to determine the RES-E volume *imported* into each country in a given hour, thereby concluding **Step 1** in what is a multi-step process to ascertain the RES-E share of all interconnector flows.

$$True = \sum_{j=1}^{n_j}(Exp_j) > 0 \;\&\; \sum_{j=1}^{n_j}(Imp_j) = 0 \qquad (3)$$

$$RES_{\%n_j} = \left(\frac{RES\ Gen_j - Dom\ Load_j}{Exp_j}\right) \qquad (4)$$

where,

- $RES\ Gen_j - Dom\ Load_j > 0$

where *j* represents the country and n_j is the total number of interconnections to country j. Exp_j and Imp_j represent electricity exports and imports respectively from country j. $RES\_\%n_j$ is the renewable share of exports from country j across its total number of interconnections n_j. $RES\ Gen_j$ and $Dom\ Load_j$ represent renewable generation and domestic load respectively in country j.

[10] There will undoubtedly be certain occasions where there are RES-E source countries that are not "origin" sources as defined here. Countries that export large amounts of RES-E in a period but also happen to import power (power that could be being wheeled through a country due to abundance of excess interconnector capacity for example) during the same period wouldn't be identified as an "origin" source of RES-E. However, the vast majority of these cases can be and are captured when renewable interconnector flows are traced across the limited number of interconnectors in the later defined steps 2-6 of this process.

Figure 4.2 and the following explanation describes how each step in the post-processing phase relates to the next in terms of accounting for RES-E transfer across interconnector capacity. In **Step 1** the figure shows Country A as the only country to successfully meet the requirements outlined in Eq. (3) and Eq. (4). In other words, Country A is the only country that is both 1) exporting and not importing power, and 2) has total renewable electricity generation that exceeds its domestic consumption in the period considered. Thus, it has domestic exports. The renewable share of these domestic exports is determined as the proportion of renewable energy that is excess to demand divided by the total export on all the countries interconnector lines. It has no wheeled exports because it is not importing on any of its interconnector lines which means that its total exports must equal its excess domestic generation. As such, interconnector flow between countries 'A – B' and 'A – S' are represented by *green* unbroken lines to signify RES-E flow in a given hour. The main objective of **Step 1** is to identify the sources of wheeled exports in each hour and assess what level of renewable energy is present in these interconnector flows. The following steps use this information as a foundation to trace the RES-E flows to their final location.

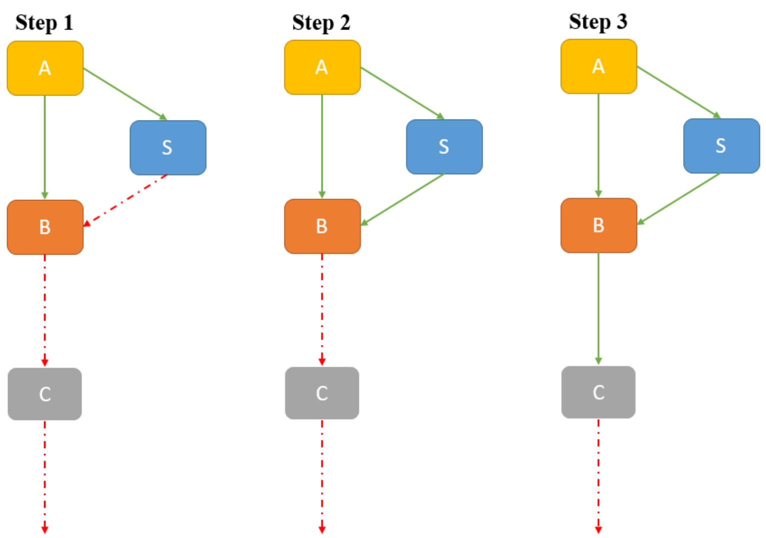


Figure 4.2: Illustrative example to explain the different steps undertaken

Step 2 sums the imported RES-E (from the sources as identified in the previous step) and the domestic RES-E in the country of focus to determine if renewable exports occur in a given hour. This calculation must abide by the condition that RES-E generation fulfils domestic load before renewable exports are possible. If under these conditions there are

RES-E exports, the percentage RES-E flows on interconnector lines are then calculated for the period in accordance to Eq. (5).

$$RES_{\%_{n_j}} = \left(\frac{RES\ Gen_j + RESImp_j - Dom\ Load_j}{Exp_j}\right) \quad (5)$$

where,

- $RES\ Gen_j + RES\ Imp_j - Dom\ Load_j > 0$

Where *RES_%*n_j is the renewable share of exports from country j across its total number of interconnections n_j. *RES Gen*$_j$ *, RES Imp*$_j$ and *Dom Load*$_j$ represent renewable generation, renewable imports and domestic load respectively in country j.

To best illustrate Step 2 the central portion of Figure 4.2 was developed. In this portion, the transfer between countries 'B – C' and 'S – B' are recalculated to identify if the flows contain RES-E. The figure shows the interconnection between 'B – C' in this step as a red broken line to indicate that no RES-E flow i.e. the combination of imported RES-E from Country A and domestic RES-E in Country B does not exceed domestic load in Country B.

However, the RES-E flow between 'B – C' has not yet fully accounted for all RES-E flow up-stream. In Step 1, the interconnector from 'S – B' had no RES-E flow because imports from Country A were not yet accounted for in Country S. In Step 2, this RES-E flow is accounted for and the interconnection between S – B is green – meaning the combination of imported RES-E from Country A and domestic RES-E in Country S exceeds domestic load in Country S and RES-E is exported from Country S. However, the interconnector 'B – C' has not yet taken account of this additional RES-E flow wheeled through Country S.

As shown in the righter most portion of Figure 4.2, this imprecision is corrected in Step 3 when the RES-E flow becomes fully accounted for across the interconnection 'B – C'. As a result, the interconnection changes to a green unbroken line which indicates RES-E flow - meaning that the combination of imported and domestic RES-E exceeds domestic load in Country B.

Step 3-6: Steps 3-6 in this work encompass a reapplication of Step 2 and further trace the RES-E flows away from the country of origin. Each reapplication uses the newly calculated domestic RES-E in countries and RES-E flows on interconnectors from the previous step to recalculate the domestic RES-E in countries and RES-E flow on interconnector lines.

The application of this methodology requires as many reapplications of Step 2 as necessary to account and trace for all RES-E flows from the originating sources. In this study, while comparing Step 5 to Step 6, the results after accounting for flows on all 58 interconnectors across Europe over the year were identical. This is to say that all RES-E flows had been accounted for by this stage and that further iterations did not change the domestic RES-E in counties and RES-E flows on interconnectors. Therefore, Step 5 in the case of this work was the final iteration.[11] These values account for renewable electricity flows all the way back to their source and provide an insight into the locations where RES-E is consumed on an hourly basis for the year 2030.

[11] The number of steps may change depending on a number of variables, such as installed renewable generation capacity, interconnection capacities, domestic load, generation and load profiles, et cetera.

4.4. Results

4.4.1. Wholesale Electricity Prices

Figure 4.3 demonstrates wholesale price differentials with 26 countries inside ±10% of the €73.21 per MWh average. Low price differentials are observed due to the increased level of interconnection capacity expected in 2030. The Czech Republic has the highest wholesale price of any electrically interconnected country simulated, it also experiences the highest level of interconnector congestion (55%) over the year. This congestion is caused by physical transmission capacity constraints and directly contributes to price formation as lower cost electricity from surrounding countries cannot be imported at a sufficient rate to further suppress the marginal price.

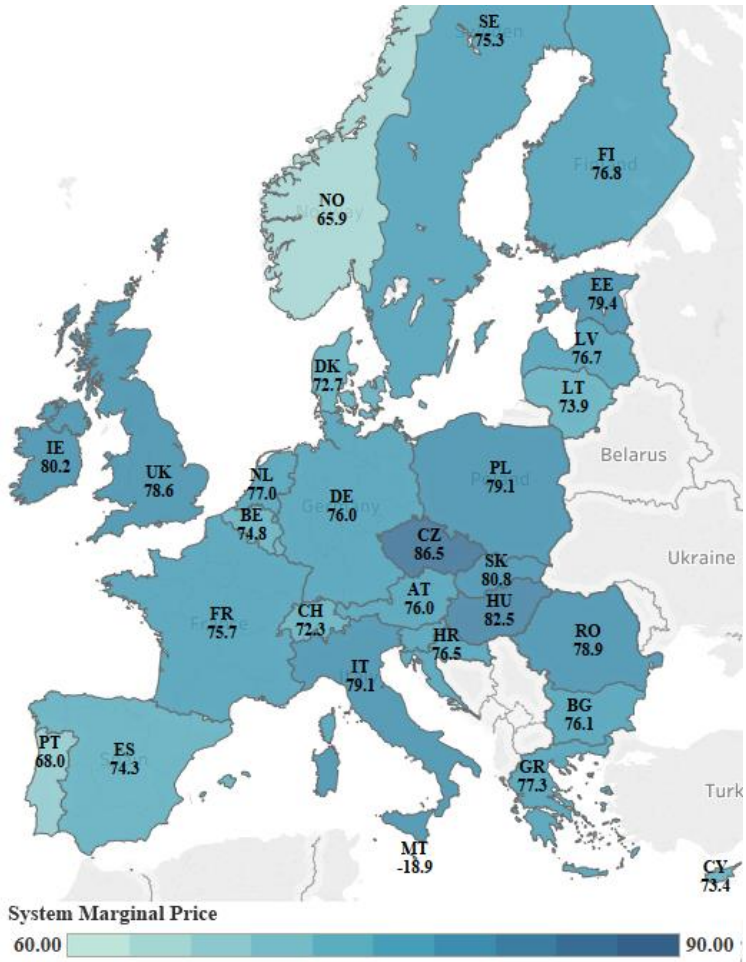


Figure 4.3: Wholesale electricity prices of the EU-28 and two non-EU countries; Norway and Switzerland[12]

[12] Due to the aggregated nature of the generation portfolio, Malta experiences a non-optimal dispatch which results in numerous hours of negative pricing.

4.4.2. RES-E Interconnector Flow

The methodology outlined in Section 4.3.2 is applied to identify and also quantify the RES-E contribution of electricity transfer between countries on a high temporal resolution. Figure 4.4, Figure 4.5 and Figure 4.6 show three insights to the findings from the post-processing phase. The figures outline the overall electricity flow and renewable electricity flow between countries along with the renewable share of the transferred electricity on an annualised basis.

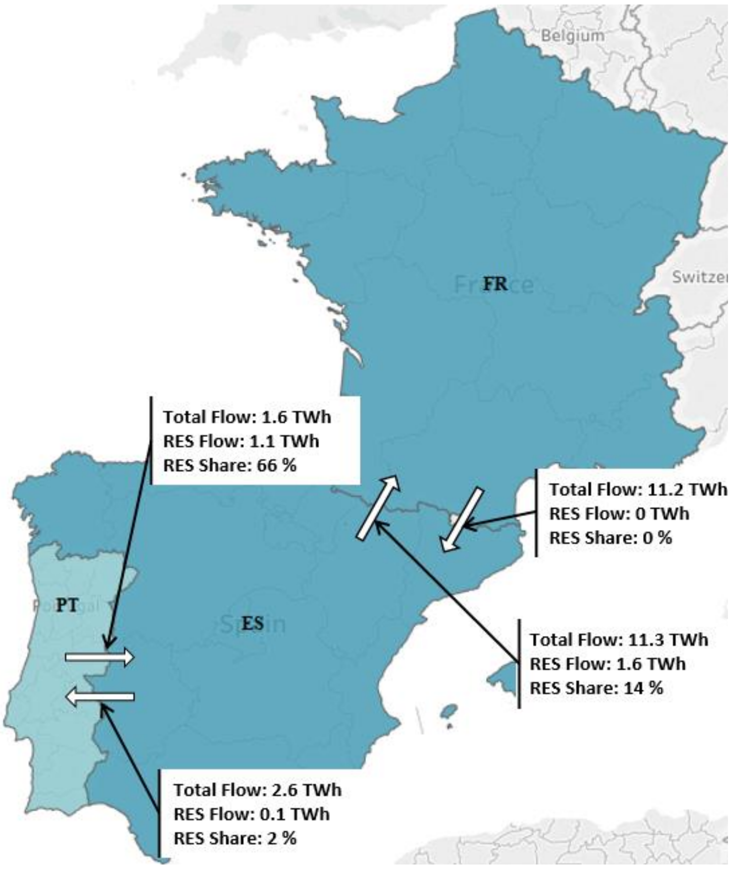


Figure 4.4: Interconnection activity between Portugal, Spain and France

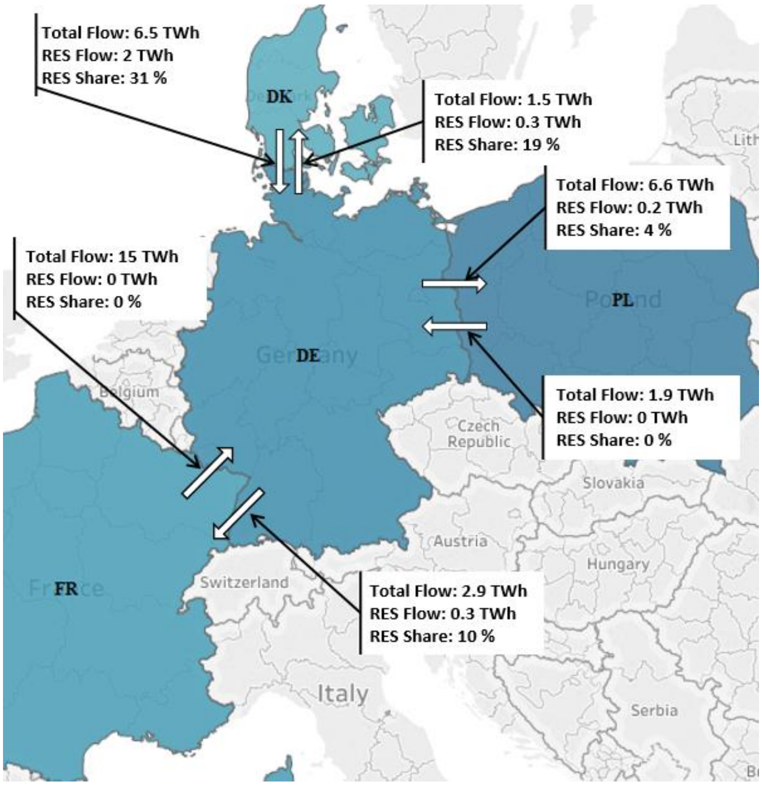


Figure 4.5: Interconnection activity between France, Germany, Denmark and Poland

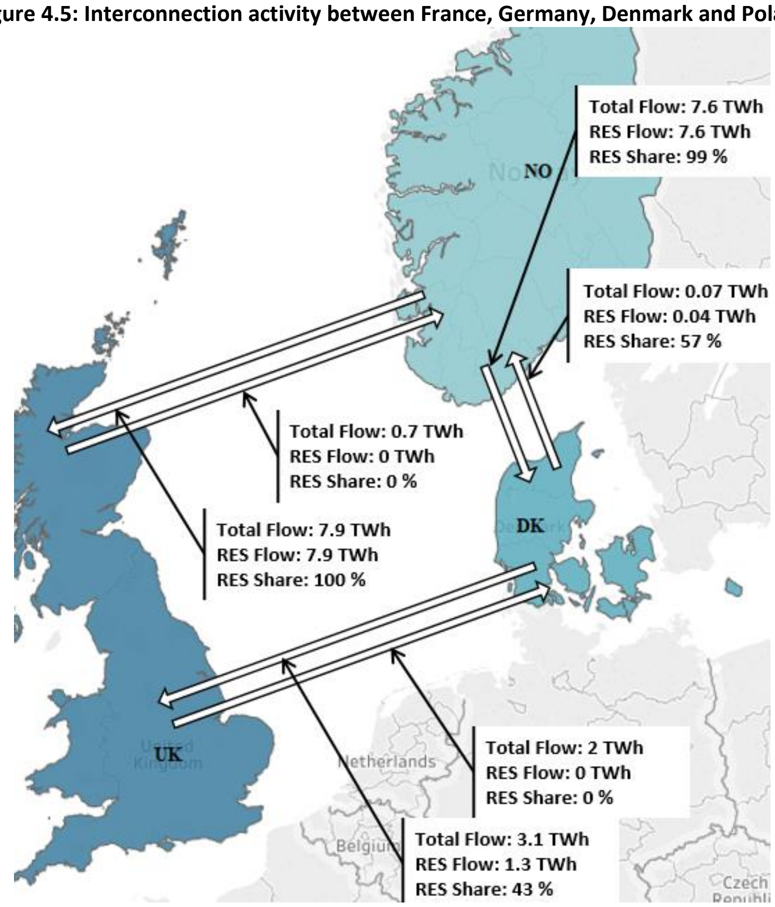


Figure 4.6: Interconnection activity between Norway, Denmark and the United Kingdom

Figure 4.4, Figure 4.5 and Figure 4.6 highlight the unequal electricity transfer between a selection of countries over a year. The figures also demonstrate the difference in RES-E share that is transferred over the same period. However, it should be reiterated that both observations are contingent on assumptions surrounding generation portfolios and renewables profiles used, demand curves, fuel costs, taxes, lack of pumped storage facilities, et cetera. Figure 4.4 shows Portugal and Spain transferring a similar amount of total electricity back and forth over the year, yet 66% of exported electricity originating in Portugal is from renewable sources while only 2% of electricity returned is considered renewable. Similarly, France exports high volumes of electricity to Spain but with no RES-E share, which is directly associated with its generation portfolio, i.e. high share of nuclear power. This can also be seen in Figure 4.5 where France is a net exporter to Germany but, again, with no RES-E share. Figure 4.5 further highlights the issue regarding RES-E share of imports-exports when analysing the interconnections between Germany-Denmark and Germany-Poland where large differences between RES-E contributions are identified. Figure 4.6 is perhaps the most striking example to show the significance, where hydro based Norwegian power is exported to Denmark and UK at 99% and 100% RES-E over the year respectively. While Norway does not import significant quantities of electricity in the simulation, the volume that is imported has a much lower RES-E content. Table 4.2 demonstrates the net RES-E share transferred on each interconnector. Remaining cognisant of the conservative assumptions surrounding scenario selection, the analysis carried out as part of this chapter estimates that 60 TWh of renewable electricity is transferred across European interconnectors in 2030 or 19% of total cross-border flow.

Table 4.2: Net renewable electricity flow transfer as a share of total electricity transfer[13]

AI-GB	**AT-CZ**	**AT-DE**	**AT-HU**	**AT-IT**	**AT-SI**	**BE-DE**	**BE-FR**	**BE-GB**	**BE-LU**
46%	15%	12%	23%	25%	25%	-10%	0%	0%	-9%
BE-NL	**BG-GR**	**BG-RO**	**CH-AT**	**CH-DE**	**CH-FR**	**CH-IT**	**CY-GR**	**CZ-DE**	**CZ-PL**
-1%	-13%	0%	-6%	6%	19%	24%	2%	-2%	0%

[13] The table contains the electricity flows to and from the all island (AI) electricity system which consists of Ireland and Northern Ireland, along with Great Britain (GB).

CZ-SK	**DE-DK**	**DE-FR**	**DE-LU**	**DE-NL**	**DE-PL**	**DE-SE**	**DK-GB**	**DK-NL**	**DK-NO**
0%	-12%	10%	6%	10%	4%	9%	43%	37%	-42%
DK-SE	**EE-FI**	**EE-LV**	**ES-PT**	**FI-SE**	**FR-AI**	**FR-ES**	**FR-GB**	**FR-IT**	**FR-LU**
34%	0%	-4%	-64%	0%	-18%	-14%	0%	-1%	0%
GR-IT	**HU-HR**	**HU-RO**	**HU-SI**	**HU-SK**	**IT-SI**	**LT-LV**	**LT-PL**	**LT-SE**	**NL-GB**
20%	-1%	-1%	-1%	0%	-1%	-3%	0%	-1%	1%
NO-DE	**NO-GB**	**NO-NL**	**NO-SE**	**PL-SE**	**PL-SK**	**SI-HR**			
79%	100%	98%	94%	0%	0%	0%			

4.4.3. Country-Specific Renewable Electricity Shares

Viewing renewable electricity in this alternative light opens 'Pandora's box' in terms of accounting for the renewable electricity shares of each country. Identifying where renewable electricity is produced, transferred to and finally, where it is consumed in high temporal resolution is an accurate means of assessing the share of the electricity sourced from renewable sources that is *actually* consumed within state. Figure 4.7 compares RES-E shares of individual countries applying the current approach long used by the European Commission (RES-E production) to the alternative approach outlined in this chapter that accounts for renewable electricity transfer across interconnectors (RES-E consumption).

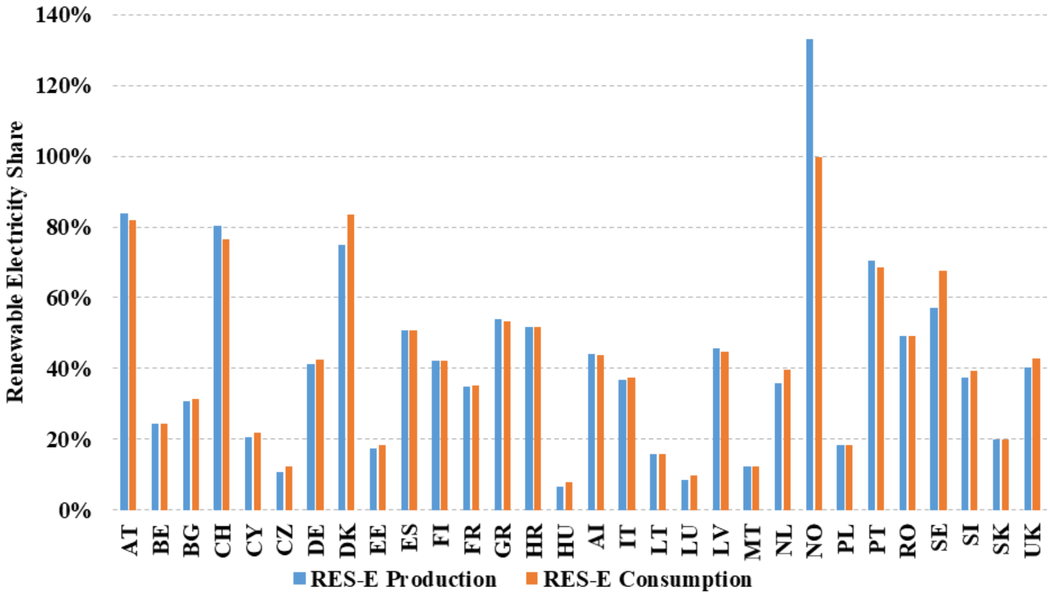


Figure 4.7: Comparing the RES-E share of 30 countries applying the traditional approach (RES-E production) and an alternative methodology proposed in this chapter (RES-E consumption) [14]

Using the approach outlined in this chapter, Figure 4.7 shows a higher number of countries with a different level of renewable electricity than what would otherwise be reported using the current production-based approach. In reality when wind generation is high in the Nordics and hydro-power capacity in Norway is generating low-cost electricity, excess generation is exported out of the Nordic region. While this electricity may be used elsewhere, it is still from a renewable energy source. The same applies when solar capacity in the more southern, warmer parts of Europe is producing high levels of power and this is transferred to load centres across the wider region, and so on. Applying the current approach used by the European Commission, while a simpler approach, does not account for this transfer.[15] For example, Figure 4.7 demonstrates that, when taken on an annualised basis, Norway has excess renewable electricity which is transferred to surrounding countries to meet their demand (if the correct price signals are in place.)[16] The traditional approach to quantifying RES-E does not capture this transfer or where RES-E is

[14] The simulation did not model generator "own use" or transmission and distribution losses, therefore Gross Final Consumption is unknown. In its place, the final electricity consumption is used to measure RES shares. For example, the RES-E Production is calculated using the renewable generation divided by the final electricity consumption of each country. RES-E Consumption uses the renewable generation plus renewable imports minus renewable export divided by final electricity consumption. It is recognised that this assumption is not aligned with the Renewable Energy Directive's methodology, however it provides an insight into the relative difference between the two approach which is the main point of the figure.

[15] The authors recognise that 'Statistical Transfers' are allowed under the Renewable Energy Directive (2009/28/EC), however this option is yet to be availed of by any Member State, at time of writing.

[16] This assumption is supported by evidence available from (Eurostat, 2016a)showing Norway producing 138 TWh of RES-E in 2015 to meet a GFC demand of 129 TWh.

consumed and therefore could be seen as a poorer approach in calculating RES-E for adjoining countries. Denmark and Sweden are examples that show the inability of the traditional approach to account for the level of renewable energy *actually* consumed within state – which in both cases is higher than otherwise would be reported, as shown in Figure 4.7.

For simplicity, measuring RES-E production is an easier option. However, as electricity markets across Europe become more intrinsically linked and transition toward a complete EU-wide internal market, the current approach may no longer be the correct strategy to capture where RES-E is consumed and importantly where it is paid for. In Section 4.5 the case study results demonstrated thus far are expanded upon to discuss issues around cross-border subsidisation, price distortion and cost inequality.

4.5. Discussion

Section 4.4 results demonstrate the difference between a consumption and production-based approach to quantifying RES-E in Europe. This section examines a number of considerations and impacts associated with the findings and discusses the possible consequences.

4.5.1. What Does a Consumption-Based Approach Offer?

A consumption-based approach improves clarity, accuracy and awareness of where RES-E is produced and it is consumed. The clarity of knowing where electricity is generated, how interconnector flows are determined and the effects of generation portfolios in neighbouring countries. Improved accuracy through the accounting of imported renewable electricity generated outside of state boundaries yet consumed within, and the awareness of potential issues that can arise when the volume and scale of RES-E transfers across the region escalate. A consumption-based approach also sheds light on issues of price distortion (caused by uncoordinated support schemes) and cross-border subsidisation (creating cost inequality).

4.5.2. Who Pays the 'True' Cost of Transferred Renewable Electricity?

The EU Target Model is designed to promote the free flow of electricity throughout Europe unaffected by network constraints or price distortions to achieve a price convergence across the region. While Figure 4.3 shows the effects of this framework in terms of a relatively shallow price range, Figure 4.4, Figure 4.5 and Figure 4.6 reveal a different perspective on unconstrained electricity flow regarding renewable electricity transfer. Acknowledging that significant volumes of RES-E capacity across Europe are supported outside of the energy market through support mechanisms, and yet interconnector flows are based on wholesale energy market prices, this creates a paradox. As more RES-E capacity is installed, wholesale electricity prices reduce further due to the merit order effect, becoming more attractive to export at a price that is *not* truly reflective of the cost to generate the power being exported. Thereby leaving the country where the renewable electricity is produced to meet the stipulations of the support schemes in place, i.e. remunerate the RES-E capacity to the agreed terms and conditions while the energy is consumed outside of state borders.

For instance, the simulation shows that the interconnection capacity from Denmark to Sweden exports (imports) approximately 1.8 (1.6) TWh over the year. When Denmark exports to Sweden the electricity is 35% RES-E compared to 0.4% when flows reverse, as can be seen from Table 4.2. Coupled with the examples shown in Figure 4.4, Figure 4.5 and Figure 4.6, this demonstrates that countries such as Denmark, Portugal, Norway and Germany for example are exposed to cost inequalities if 1) electricity is traded on interconnectors using its wholesale price (which it is and will continue to do so in line with the EU Target Model) and 2) RES-E capacity is supported outside of the energy market (which is currently the case in most European countries). This longstanding concern around price distortion effects caused by pecuniary externalities is a well published topic, see (Gore et al., 2016, Glachant and Ruester, 2014, Fouquet and Johansson, 2008, Couture and Gagnon, 2010, Joskow, 2008, Lehmann and Gawel, 2013, Meyer and Gore, 2015, Roques, 2008, Buchan and Keay, 2016, IEA, 2016a). Nevertheless, with large volumes of RES-E capacity required to achieve the future goal of a decarbonised power sector, this challenge may be amplified and become a more widespread problem noting that this chapter demonstrates a conservative view of what may actually unfold in 2030 (Capros et al., 2016).

Quantifying the financial implications for countries net-exporting RES-E is a challenging task as there has been little coordination between Member States when setting up RES-E support schemes across Europe over the years.[17] Neighbouring countries may endure dissimilar levels of price distortion due to the differing support structures, remuneration levels and/or contract lengths. Bearing in mind the current Member State specific RES-E targets for 2020, in simple terms this means if a country could not achieve the necessary uptake in RES-E capacity to meet national targets, the remuneration offered or scheme framework may be altered to increase its attractiveness through higher remuneration, longer contracts, or less risk-exposure. Ireland for example, changed its RES-E support in 2007 from a competitive bidding process to a centrally administered price setting scheme to increase profitability for RES-E generation capacity. According to Global Wind Energy Council & International Renewable Energy Agency (2013), many projects awarded financial support through the competitive bidding process in Ireland had not been built due to "*low bidding prices and lack of profitability*" (p.100).[18] In a similar vein to price distortions stemming from uncoordinated capacity mechanisms as discussed by Meyer and Gore (2015), Glachant and Ruester (2014), Gore et al. (2016), Gaffney et al. (2017b), uncoordinated RES-E support schemes may be viewed in the same light during the transition to a future regional market based on undistorted price signals. However, equally as important is the need to implement a framework for remunerating renewable electricity transferred across boundaries that improves cost equality – paying the 'true' cost rather than market price.

4.5.3. How to Address Price Distortion

Viewing these concerns in the correct context is essential; meaning that the issue is borne out of a requirement for cross-boundary interactions, therefore the solution must also be viewed in the same geographical context. Introducing a coordinated approach to RES-E support schemes through a European agency could provide the solidarity needed for cost equality to thrive, and thereby maximising societal welfare for all European electricity consumers. An agency appointed to administer the renewable electricity affairs of the

[17] While it must be recognised that the European Commission has used its "autonomous control power" regarding the policing of national state aids to shape support schemes in some way, as alluded to by Buchan and Keay (2016) and also having recently introduced a working document on guidance for the design of renewable support schemes (European Commission, 2013b), it is recognised that support sharing and full coordination has not yet been achieved to date.

[18] For more information on the development of wind power in Ireland and the entire Irish electricity system between 1916-2015, see (Gaffney et al., 2017a)

region that takes cognisance of individual economic, societal, technical and environmental conditions to create a level playing field, free of price distortion created by differing support structures. This may not be an excessively unrealistic proposal, instead it could be recognised as a new, or an expansion of an existing, department within the Agency for the Cooperation of Energy Regulators (ACER) for example. An agency which was created through the EU Third Energy Legislative Package (2009/72/EC) to ensure the smooth functioning of the internal energy market (European Parliament and Council, 2009b).[19]

The chosen agency could also be responsible for accurately quantifying renewable electricity shares and remunerating producers from the country that consumed their electricity instead of where it has been produced – effectively redistributing the cost of renewable electricity across state boundaries to improve cost equality during Europe's transition to a decarbonised system. In addition, to further this cause it could also adopt a change in market boundaries as proposed by the ISLES project (PPA Energy, 2012) which would offer a transparent mechanism for trading of renewable subsidies between Member States. The ISLES project proposed that market boundaries be moved offshore such that offshore renewable generation is in the market where most of that generation is consumed. A move in this direction to apply both these measures could be seen as a reform or even an evolution of the 'statistical transfers' permitted between Member States in Article 6 of the Renewable Energy Directive and Article 8 of the latest Renewable Energy Directive draft (European Commission, 2016d).

Increasing the accuracy of cost distributions associated with the consumption of renewable electricity may also provide secondary gains. Aside from reducing the level of revenue required to remunerate RES-E generation in an exporting country, this approach may lower the economic barriers surrounding the cost to consumers of developing higher levels of RES-E capacity. If, for example, a country has the correct topography and climate for hydro-powered generation, then the cost as well as the benefit of this renewable energy source can be shared with neighbouring nations. This may encourage further development in countries rich in potential renewable assets such as geothermal, solar, biomass, biogas,

[19] This may be a timely suggestion as there is currently a proposal to strengthen ACER's powers and responsibilities included in the draft directive on the Internal Electricity Market (European Commission, 2016e)

wave, tidal and wind energy by lowering the economic barriers which often add weight to institutional and organisational barriers as shown in publications by Lund and Quinlan (2014), Byrnes et al. (2013), Verbruggen et al. (2010), Lund et al. (2014a), Foxon et al. (2005), Scarpa and Willis (2010), Painuly (2001), Reddy and Painuly (2004), Hvelplund et al. (2017).

4.5.4. Is There Appetite For Change?

Buchan and Keay (2016) highlight that the European Commission *"has twice tried, and twice failed, to persuade EU governments to adopt a harmonised EU-wide subsidy system."* (p.7). Therefore, an appetite appears to exist at EU level within the European Commission. Furthermore, Article 5 of the latest Renewable Energy Directive draft the European Commission includes plans to open access for RES-E support schemes to installations located in other Member States (European Commission, 2016d). However, legal conflicts such as the *PreussenElekra* case of 2001,[20] or more recently the *Ålands Vindkraft* case in 2014,[21] highlight the individual nature of EU Member States and the 'parochial' thinking that exists regarding environmental targets – albeit the very nature of individual targets encourages this behaviour.

The issue, is perhaps best epitomised by the Ålands Vindkraft case, where a windfarm situated in the Åland archipelago of Finland applied for a Swedish RES-E support scheme as it was directly connected to the Swedish system but not that of Finland. The application was rejected on the grounds that it was unfair for Swedish consumers to remunerate a wind farm contributing to Finland's RES target. Once this occurred, the boundaries of environmental protection were clearly drawn by Sweden, even in the face of breaching European energy market law surrounding the free movement of goods, i.e. electricity. While the European Court of Justice required justification from Sweden regarding the case, the ruling was in Sweden's favour as the argument was successfully made that the Renewable Energy Directive *does* permit the trans-boundary RES-E support schemes but *does not* require it (European Parliament and Council, 2009a). Therefore, Sweden were found to have acted within the boundaries of EU law.

[20] For more information, see: http://curia.europa.eu/juris/liste.jsf?language=en&num=C-379/98
[21] For more information, see: http://curia.europa.eu/juris/liste.jsf?num=C-573/12

Despite the European Court of Justice ruling, Durand and Keay (2014) believe that the Ålands Vindkraft case raises more questions than it answers regarding the relationship between environmental protection (and individual Member State targets) and its place within the European energy market law. Durand and Keay (2014) highlight that other Member States have cited the Ålands Vindkraft case as a justification for discriminatory practices. Germany for example, cited the case while attempting to introduce a surcharge on imported electricity through a new renewable energy law that would be used to finance domestic RES-E producers.[22]

While it is the opinion of Buchan and Keay (2016) that cross-border subsidy sharing may be a bridge too far at the time of publication, it must be seen as progressive that Norway and Sweden introduced a joint support scheme that includes an international agreement between the countries to recognised 'green energy' produced in another jurisdiction,[23] or that the German-Danish cross-border solar photovoltaic electricity auction was launched in 2016 (IEA, 2016b), or indeed, when the European Commission included plans supporting (and requiring) subsidy sharing in Article 5 of the latest Renewable Energy Directive draft (European Commission, 2016d). Remaining cognisant that the 'green energy contributions' conversation regarding joint, cross-border schemes will be 'null and void' post-2020 once national RES targets are relinquished for 2030, issues surrounding cross-border subsidisation of RES-E on a supranational scale will remain, and potentially increase due to heightened levels of both RES-E generation and installed interconnection capacity.

4.5.5. Considerations Associated With a Consumption-Based Alternative Approach

Complexity, complexity, complexity. This proposal ensures much of it. Calculating the locations where renewable electricity is generated, how much is transferred, where it actually consumed, et cetera, is all involved work. Nevertheless, the alternative is to continue to use a methodology which may not be fit for purpose. Increasing the installed capacity of different renewable energies both in Europe and globally adds to the already

[22] For more information, see: http://www.reuters.com/article/eu-energy-idUSL6N0PE24C20140703 and http://curia.europa.eu/juris/liste.jsf?num=T-47/15

[23] The amount of 'green energy' contributed toward national RES targets would depend on the level of investment in the joint project.

multifaceted world of the electricity sector. As the penetration of renewable energies increase, as does the need for interconnection, support mechanisms, along with issues surrounding the 'missing money' problem, price distortions, and many more. While this chapter does not provide the solutions to all these issues, it may be seen in a similar light to that published by Ji et al. (2016) as a 'thought-provoker', one that tries to unearth a different way of thinking about the future electricity sector.

Further research is necessary in numerous areas to add layers to this proposal. For instance; the identification of regulatory and institutional barriers is essential for any movement towards a new approach for calculating RES-E shares and establishing a framework around the cost inequality issue, identifying how to best approach this redistribution of costs are two important areas of research.

4.6. Conclusion

This chapter proposes an alternative approach for quantifying the RES-E share of individual countries based on the volume consumed rather than produced to address potential inadequacies associated with the modern-day approach. As global power sector portfolios are undergoing a technology transformation to achieve carbon-neutrality over the long-term, renewable generation is fundamental to the cause along with high levels of interconnection to help facilitate the transition and remain as part of the enduring solution.

While increased interconnection capacity adds to the operational aspect of system control as non-synchronous RES-E can be safely and securely managed without curtailment being the first option, it also exacerbates an underlying issue with price distortions stemming from out-of-market financial support schemes that can decrease wholesale market prices. A paradox exists: as renewable generation (receiving out-of-market support) increases, wholesale electricity prices decrease, becoming more attractive to export at a price that is *not* truly reflective of the cost to generate that power. Consequently, this price distortion creates a cost inequality as consumers are left to remunerate the renewable electricity producer while the energy is consumed out of state. Using the EU Target Model as a case study, this chapter provides an awareness to the potential volume and scale of the issue in a sector aiming for long-term de-carbonisation. The chapter shows that even in a conservative 2030 scenario that significant volumes of renewable electricity is likely to be transferred on annual basis. This approach should not be considered exclusive for Europe, instead it could be thought of as being applicable to any region with a similar nexus between renewable electricity generation and interconnection to surrounding systems.

This chapter suggests that tackling price distortions associated with renewable generation support mechanisms may be best approached from a supranational perspective. An agency, such as the Agency for the Cooperation of Energy Regulators (ACER) within the EU, could provide the solidarity needed for cost equality to thrive, thereby maximising societal welfare for all electricity consumers in the region. Appointed to administer the renewable electricity affairs of a region, this agency should take cognisance of individual economic, societal, technical and environmental conditions to create a level playing field, free of price distortion created by differing support structures. An agency responsible for accurately quantifying renewable electricity shares and remunerating producers from the country that consumed their electricity instead of where it has been produced – effectively redistributing the cost of renewable electricity across state boundaries to improve cost equalities during the transition to a decarbonised system.

Increasing the accuracy of cost distributions associated with the consumption of renewable electricity may also provide secondary gains. Aside from reducing the level of revenue required to remunerate RES-E generation in an exporting country, this approach may lower the economic barriers surrounding the cost to consumers of developing higher levels of RES-E capacity. If, for example, a country has the correct topography and climate for hydro-powered generation, then the cost as well as the benefit of this renewable energy source can be shared with neighbouring nations – aligning with aspects present in the Renewable Energy Directive around subsidy sharing, joint projects and statistical transfers, improving investment signals and issues surrounding long-term security of electricity supply.

The complexity associated with quantifying RES-E based on the proposed approach will be significantly higher than the status quo. The alternative is to continue to use, what may be perceived as an increasingly inaccurate methodology. Measuring RES-E by production may be viewed as a 'quick and easy' approach. However, as electricity markets worldwide become more intrinsically linked and transition toward a de-carbonised sector with high renewable generation capacity, simplicity may no longer be the correct strategy for reasons alluded to.

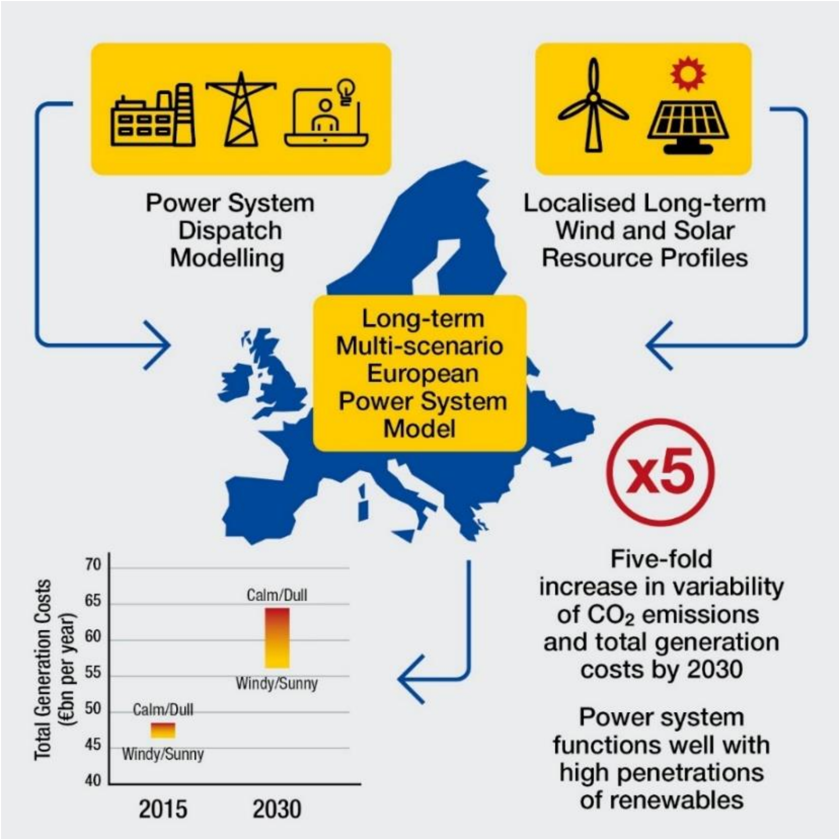
Chapter 5: Impacts of Inter-Annual Wind and Solar Variations on the European Power System

5.1. Abstract

Weather-dependent renewable energy resources such as wind and solar are playing a key role in decarbonising electricity. There is a growing body of analysis on the impacts of wind and solar variability on power system operation. Existing studies tend to use a single or typical year of generation data, which overlooks the substantial year-to-year fluctuation in weather, or only consider variation in the meteorological inputs, which overlooks the complex response of an interconnected power system. Here, we address these gaps by combining a detailed continent-wide model of Europe's future power system with 30 years of historic weather data. The most representative single years are 1989 and 2012, but using multiple years reveals a five-fold increase in Europe's inter-annual variability of CO_2 emissions and total generation costs from 2015 to 2030. We also find that several metrics generalise to linear functions of variable renewable penetration: CO_2 emissions, curtailment of renewables, wholesale prices, and total system costs.[1]

[1] Published as: COLLINS, S., DEANE, P., Ó GALLACHÓIR, B., PFENNINGER, S. & STAFFELL, I. 2018. Impacts of Inter-annual Wind and Solar Variations on the European Power System. Joule, 2, 2076-2090.

5.2. Graphical Abstract



5.3. Introduction

Variable renewable energy (VRE) technologies, namely wind and solar photovoltaics (PV), have grown over four-fold in capacity in Europe over the last decade from 62 GW in 2007 to 260 GW in 2016 (IRENA, 2017c) and are reducing power sector emissions worldwide. However, their effects on system operation include reduced market pricing, increased interconnector flows, greater need for balancing, as well as reserve and curtailment of renewable power (Bird et al., 2016, Pean et al., 2016, Higgins et al., 2015, Sensfuß et al., 2008, Würzburg et al., 2013, Winkler et al., 2016). Long-term energy system models, used to project technology pathways for policy development, struggle to capture climatic variability and thus poorly represent challenges associated with decarbonisation of the electricity sector (Poncelet et al., 2016a, Pietzcker et al., 2017). Many studies use a single or small number of years of meteorological data which neglects the impact of long-term temporal variability of weather on the power sector (Lu et al., 2009, Schroeder et al., 2013, Pfenninger and Keirstead, 2015, Rodriguez et al., 2015, Widen, 2011). Many studies also focus on a single country or small regions (Drew et al., 2015, Andresen et al., 2015, Olauson and Bergkvist, 2015, Staffell, 2014, Staffell and Green, 2014) which neglects the corresponding impact of spatial variability. Crucially, this neglects the large-scale temporal and spatial variations and correlations seen in weather systems (Bonjean Stanton et al., 2016, Schaeffer et al., 2012, Klein et al., 2013, Chandramowli and Felder, 2014). Insufficient temporal and spatial resolution within these models means that the operational challenges of such variability are not sufficiently captured, regardless of the quality of the input data (Pfenninger et al., 2014, Poncelet et al., 2016a, Collins et al., 2017b).

Various methods have been developed to address limitations of long-term energy system models in capturing wind and solar variability(IRENA, 2017b, Pfenninger, 2017a). Studies are beginning to make use of longer-term and more spatially explicit datasets. For example, Bloomfield (Bloomfield et al., 2016) and Pfenninger (Pfenninger, 2017a) both consider 25 years of weather data within the UK to explore variability in optimal generation investments, but considering a single country in isolation neglects the potential for balancing renewable intermittency through international trade. Shaner (Shaner et al., 2018), Olauson (Olauson et al., 2016), Burtin (Burtin and Silva, 2015) and Grams (Grams et al., 2017) combine long-term datasets with wider geographic scope (The United States, Scandinavia and Europe), but in their analyses of long-term variability they only explore the statistical properties of demand net of renewable output, ignoring the constrained responses of real power systems. Existing work fails to explore the full extent of renewable variability impacts across a continent-scale electricity system. Without modelling the limited interconnection between countries, the flexibility of conventional generators and the cost of backup capacity, implications of increasing variable renewable generation such as cost and carbon emissions are therefore not yet fully understood. The recent controversy surrounding Jacobson's (Jacobson et al., 2017) and Clack's (Clack et al., 2017) divergent views on the decarbonised US energy system underscore the importance of model assumptions on results. Jacobson proposed that a US transition to a 100% wind, solar and water fuelled energy system was cheap and readily achievable. However, worried that policy makers were using Jacobson's paper for scientific support, Clack published a paper criticising their work; stating that their work involved errors, inappropriate methods, and implausible assumptions. Their high-profile disagreement featured in the New York Times (Porter, 20th of June 2017) and illustrates how closed and opaque modelling harms the credibility of work in this field (Porter, 20th of June 2017), and prevents users and readers from fully understanding the limitations of model outputs (Nature Energy Editorial, 2017). Here, we address all these gaps by performing a multi-scenario analysis of the European power system with an industry standard power system dispatch model using 30 years of wind and solar profiles developed using open-access weather data. Our complete model is openly available (see https://www.renewables.ninja/downloads and https://www.energyexemplar.com for PLEXOS model).

Ideally, such a study would also incorporate long-term variability in hydro generation (due to precipitation) and electricity demand (due to temperature). However, these are nascent areas of research so they cannot yet be modelled with sufficient confidence at the continental-scale to generate meaningful results (unlike wind and solar) (Fosso and Belsnes, 2004, Hyndman and Fan, 2010). The impact of longer-term climate change on variability of renewable resources also merits consideration but current thinking suggests this will be insignificant over Europe within the time horizon of this study (Hdidouan and Staffell, 2017, Jerez et al., 2015, Crook et al., 2011, Pryor and Barthelmie, 2010, Wohland et al., 2017, Kovats et al., 2014).

5.4. Modelling

As in chapters 3 and 4, we use a pan-European electricity dispatch model developed in PLEXOS (Energy Exemplar, 2018a) using a soft-linking methodology (Deane et al., 2012), which captures power station characteristics and constrained transmission of power between countries. We model the least-cost dispatch of electricity under several levels of decarbonisation ambition across 29 countries at hourly resolution while respecting the technical constraints of generators and levels of international transmission capacity. We run the model for a 2015 baseline system and five official scenarios which define electricity demand, renewable energy penetration and the installed fleet of power stations in 2015 and 2030 respectively. Together, these show how system operation changes with decarbonisation ambition. The 2015 baseline system is based on historic electricity demand profiles from ENTSO-E for this year (ENTSO-E, 2015) and the installed capacity mix from the EU Reference scenario (European Commission, 2016b) for this year (given historic data from this year formed the inputs to its development). The future scenarios are based on the European Commission’s EU Reference Scenario (European Commission, 2016b) and

ENTSO-E's four 'Visions' used to inform the ten-year network development plan (ENTSO-E, 2016b). These possible futures encompass a broad range of ambition towards achieving the EU 2050 Roadmap sustainability goals, which translates to various penetrations of different technologies (particularly VRE generation) across the scenarios considered. In terms of electricity demand this translates to the wide range of demand response, electric vehicle penetration and electrification of heating, all of which are endogenous in the demand profiles used. An overview of all these scenarios is shown in Table 5.1 and are further detailed in (European Commission, 2016b) and (ENTSO-E, 2016b). Interconnection net transfer capacities used in this work were based on historical 2015 values for the 2015 baseline simulation and projected reference capacities for 2030 were used in the other scenarios and were from ENTSO-E's scenario development informing the ten-year network development plan (ENTSO-E, 2016b).

Table 5.1: Comparison of scenarios considered in this work. Variable renewable generation sources discussed in the context of this work consist of wind and solar PV generation only.

	2015 System	EU Reference 2030	Vision 1 2030	Vision 2 2030	Vision 3 2030	Vision 4 2030
Electricity Demand (TWh)	3,103	3,752	3,434	3,251	3,376	3,616
Variable Renewable Capacity (GW)	241	447	388	390	572	614
Fuel Prices (€/GJ):						
Natural Gas	6.6	9.7	9.5	9.5	7.2	7.2
Oil	8.2	16	17.3	17.3	13.3	13.3
Coal	2	3.5	3.0	3.0	2.8	2.2
CO_2 Price (€/t)	7.5	32	17	17	71	76
Merit Order	Coal before gas	Coal before gas	Coal before gas	Coal before gas	Gas before coal	Gas before coal

These six power system scenarios were modelled with 30 years of synthesised hourly output (1985 - 2014) from each country's wind and solar fleet, derived from the Renewables.ninja models (Staffell and Pfenninger, 2016, Pfenninger and Staffell, 2016). These output profiles differ between scenarios due to the assumed wind capacity and share of onshore and offshore. The productivity of German wind farms, for example, ranged from 19.9% in 2015 to between 26.6% and 30.8% in 2030. Further information regarding the methodology, models and data used (including maps displaying the mean and inter-annual variability of these wind and solar profiles) can be found in the proceeding Methods section (section 5.7) and in Appendix B.

5.5. Results

5.5.1. Power System Evolution under Different Degrees of Ambition

The scenarios we use assume that energy sector decarbonisation is achieved primarily by increasing the share of variable renewable generation, rather than other options such as nuclear or carbon capture and storage (CCS). Table 5.2 provides an overview of how the operation of the power sector changes with different degrees of decarbonisation ambition under these scenarios (i.e. different amounts of VRE deployment) and quantifies how year-to-year variation in weather patterns affect the power sector's operation. Table 5.2 displays results for three scenarios. The mean of each metric is listed followed by its coefficient of variation across all weather years in brackets. Wholesale electricity price is defined as the marginal cost of electricity in each region, reflecting the shadow price on the electricity demand-supply constraint. This captures an uplift element to account for start-up costs of thermal plant but excludes taxes, capacity payments or ancillary services. Scarcity pricing (a price cap in the event of unserved energy) was used in the model in the determination of regional wholesale energy prices (New Zealand Electricity Authority, 2018). This should be interpreted as an energy-only price in a perfect wholesale market where no market power or strategic behaviours occurs. The absence of market power is a key aim of the European internal electricity market and is representative of European power market function. However, in reality, markets do not always function perfectly, with an example being in the first quarter of 2017 when several European countries implemented export limits and bans to prevent supply disruptions which reflected a lack of cooperation in the internal electricity market (European Commission, 2017a).

Table 5.2: Overview of simulation results for three scenarios representative of the range of ambition in this work in terms of renewable energy penetration. For each metric, the mean and coefficient of variation across all weather years are listed. These scenarios are the 2015 System, the EU Reference and ENTSO-E Vision 3 scenarios (see Appendix B for the full range of scenarios). Total generation cost is defined as the sum of total short-run generation costs: fuel, emissions, start-up and shutdown costs.

	2015 System	**EU Reference 2030**	**ENTSO-E Vision 3 2030**
Wholesale Electricity Price (€/MWh)	44 (±2.2%)	82 (±2.1%)	60 (±3.6%)
Price Received by Wind Generation (€/MWh)	48 (2.2%)	81 (1.3%)	56 (4.4%)
Price Received by Solar Generation (€/MWh)	45 (2.8%)	86 (1.7%)	40 (4.5%)
Price Received by Gas Generation (€/MWh)	69 (2.5%)	92 (2.0%)	95 (1.8%)
Price Received by Coal Generation (€/MWh)	50 (2.5%)	91 (1.2%)	128 (5.3%)
Price Received by Nuclear Generation (€/MWh)	40 (2.2%)	75 (1.3%)	61 (3.2%)
Total Generation Cost (€B)	47.11 (±0.8%)	86.83 (±2.1%)	50.28 (±4.2%)
Total CO_2 Emissions (Mt)	1001[2] (±1.0%)	917 (±1.3%)	233 (±5.0%)
Emissions Intensity (gCO_2/kWh)	322.6 (±1.0%)	247.8 (±1.3%)	68.5 (±5.0%)
RE Generation	36.7% (±1.0%)	47.2% (±1.4%)	68.4% (±1.3%)
VRE Generation	13.4% (±2.8%)	24.4% (±2.7%)	35.1% (±2.8%)
VRE Curtailment	0.1% (±26.3%)	0.1% (±16.8%)	4.3% (±10.7%)
Average Interconnection Congestion	26.0% (±0.9%)	19.1% (±2.6%)	29.7% (±1.0%)
Total International Electricity Flow	267 TWh (±0.7%)	355 TWh (±2.3%)	411 TWh (±1.2%)

[2] Total electricity emissions from this base year simulation is within 3% of the official verified emissions (1025 Mt) for this year, using our historical 1985-2014 weather data (European Environmental Agency, 2016b).

As shown in Figure 5.1A and Figure 5.1B, approximate linear relationships are observed between increases in VRE penetration[3] across the scenarios and CO_2 emissions [R^2=0.85] and VRE curtailment [R^2=0.92]. The quality of fit for curtailment reduces to R^2=0.79 when the 2015 System simulation is included, suggesting that Europe is expected to begin experiencing notable curtailment due to international constraints beyond a VRE penetration of 22% energy (which is anticipated to be reached by 2027 under conservative EU Reference scenario conditions (European Commission, 2016b)). While this simplifies the power system's response by neglecting distribution-level constraints, it provides useful insight into the underlying trends caused by variable renewables and agrees with the broad trajectory from other studies (e.g. the IEA projects 7% curtailment in 2040 (IEA, 2017a)).

The year-to-year operational volatility increases with VRE penetration as evidenced by the five-fold increase in variability (defined as the inter-annual coefficient of variation) of CO_2 emissions and total generation costs across the scenarios, as shown in Table 5.2. Due to the reduction in overall CO_2 emissions and increase in VRE penetration, variability of CO_2 emissions increases five-fold even though the magnitude of CO_2 emissions variability (inter-annual standard deviation) remains broadly consistent across scenarios. This variability in CO_2 emissions implies greater variability in the operation of conventional coal and gas fired generation which generate less with increased variability in their operation. Variability on a country level is greater due to the geographic smoothing of weather systems at a continental level. For example, Great Britain experiences up to nine-fold increase in variability of CO_2 emissions and seven-fold increase variability of total generation costs, see Appendix B. Figure 5.1C and Figure 5.1D show how the range of wholesale market pricing and total generation costs widens with VRE penetration. Off-model assumptions for fuel and CO_2 prices strongly influence these outputs, so low correlation is seen across all scenarios between VRE and wholesale prices or total generation costs [$R^2 < 0.1$].

The lines plotted in Figure 5.1C and Figure 5.1D show the linear relationships within each scenario, in which only weather inputs change. Total generation costs (Figure 5.1D) bear strong correlation with average VRE penetration within each scenario [R^2=0.92] though less

[3] Defined throughout this chapter as the proportion of total annual demand for electrical energy met by variable renewable (wind and solar photovoltaic) sources

so for wholesale market pricing (Figure 5.1C) [R^2=0.50]. These lines become steeper with increased penetrations of VRE, indicating that the impact of VRE resource variability on electricity market economics will strengthen and become increasingly volatile with greater penetrations of VRE.

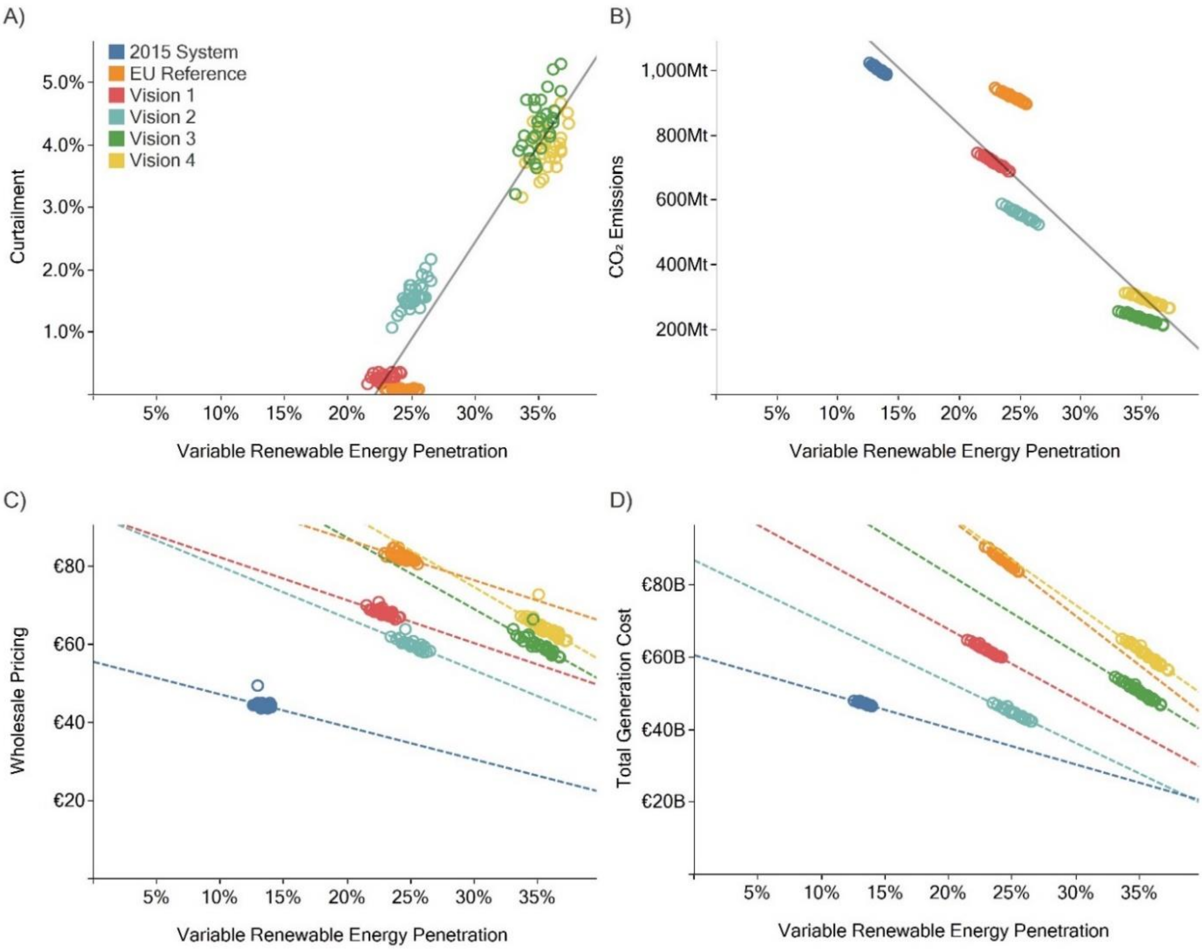


Figure 5.1: The relationships between VRE generation penetration and electricity system metrics across historic and 2030 scenarios. The four panels show (a) VRE curtailment (2015 hindcast excluded) (b) CO_2 emissions, (c) wholesale electricity prices and (d) total generation cost across all scenarios. Individual points are for individual weather years from the 30-year VRE generation dataset, colours indicate the scenarios. Linear regressions across all scenarios are shown in the top panels, and within individual scenarios in the bottom panels. In these lower panels, C and D, the fitted lines are extrapolated well beyond the range of the data points. They are intended to illustrate the general trend, and deliberately do not indicate confidence in the predicted values.

5.5.2. Market Operation and the Displacement of Conventional Fossil-Fuelled Generation

With increased VRE penetration and lower fossil generation, carbon price plays a more significant role in determining wholesale electricity prices under the highly decarbonised Visions 3 and 4. Fuel prices remain the dominant influence in other scenarios. As shown in Table 5.2, average wholesale price increases under greater decarbonisation, but this increase is not shared equally across all generating technologies. The merit order effect (Hirth, 2013, Staffell, 2017, Sensfuß et al., 2008), whereby VRE depresses prices at times of high output and thus cannibalises its own revenue, intensifies – especially for solar PV. The price received by Solar PV generators decreases relative to 2015 levels. For wind generators, it grows more slowly than the average wholesale price.

The price received by fossil fuelled generators increases relative to wholesale prices under decarbonisation as their flexibility is more highly valued. However, their utilisation is reduced and sees greater year to year variability. Fossil-fuelled generators account for 63% of power production in the 2015 system scenario, but this falls to just over 30% in RE>60% scenarios (ENTSO-E Visions 3 and 4). This contributes to European emissions intensity falling from an average across weather years of 322 gCO_2/kWh in the 2015 reference scenario to below 100 gCO_2/kWh in those scenarios.

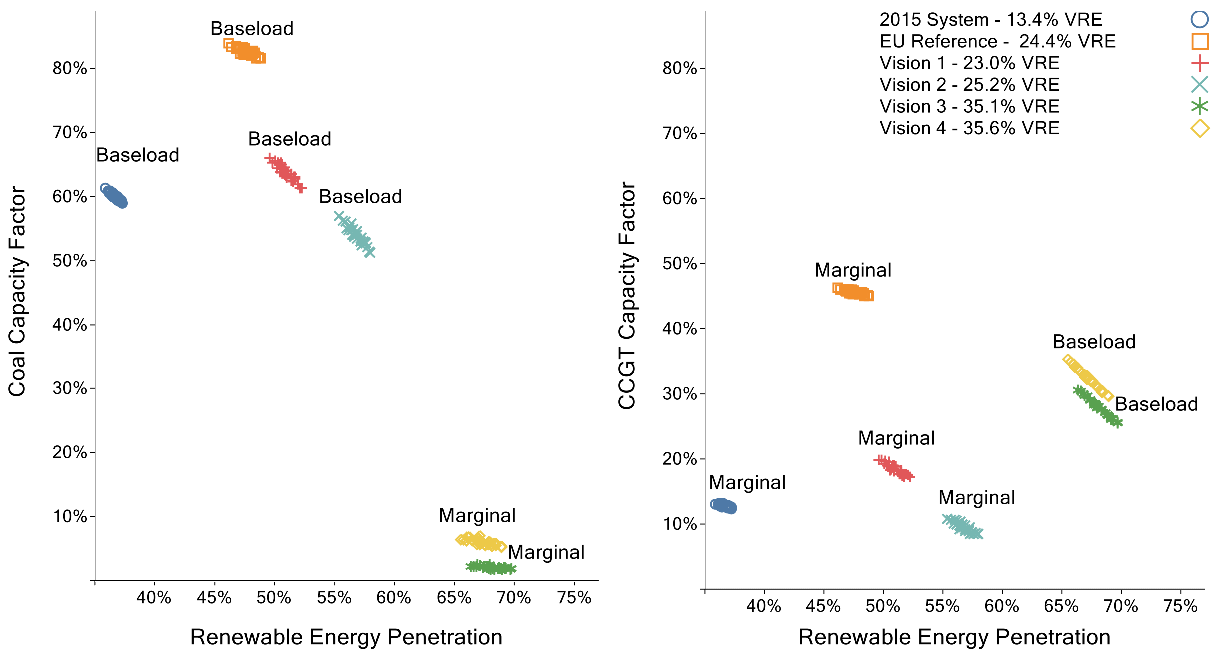


Figure 5.2: Annual European coal and natural gas combined cycle gas turbine (CCGT) capacity factors by scenario , showing the range across each of the 30 historical weather years used. Total renewable energy is defined as VRE plus biomass and hydro power. The labels indicate whether the mode of generation is baseload or marginal in the merit order of each scenario.

Figure 5.2 demonstrates that baseload fossil-fired technology (gas in Visions 3 and 4, coal otherwise) is most affected by the inter-year variability of VRE because it provides balancing for year-by-year variation in resource availability. Given that Figure 5.2 depicts the pan-European operation of conventional generators it masks the more substantial country-level variability. Figure 5.3 identifies this variability within selected countries and scenarios.

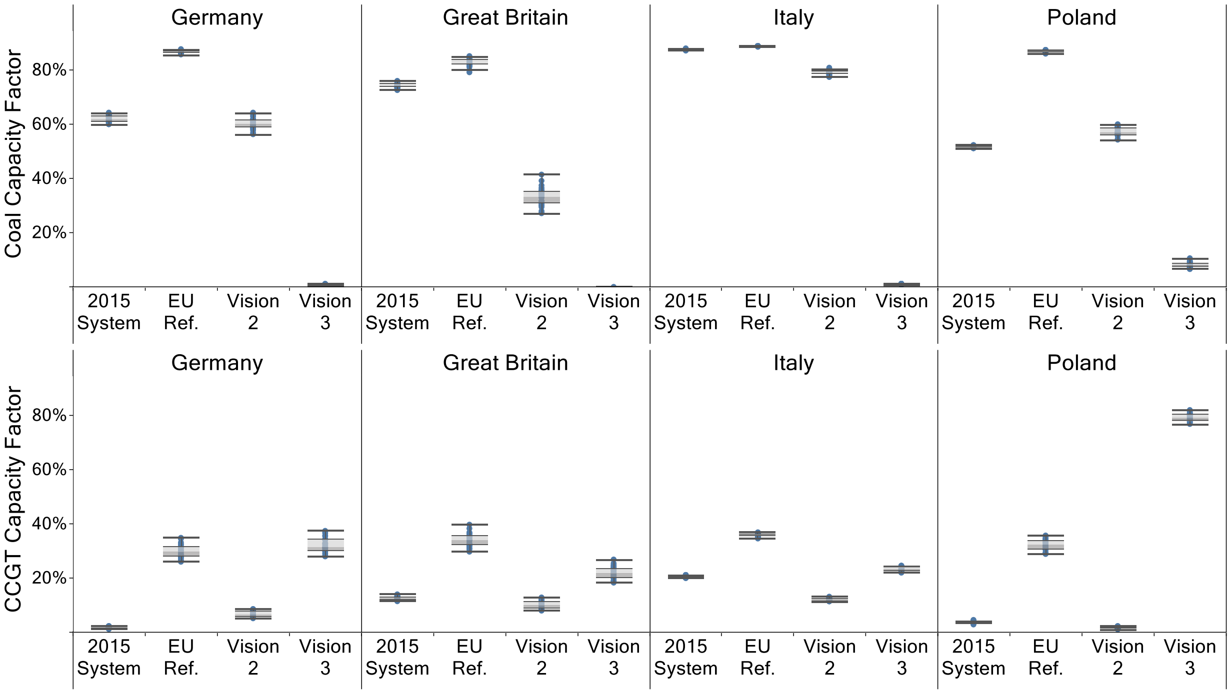


Figure 5.3: The range of capacity factors for coal and natural gas CCGT generation across the 30 years of modelled weather conditions within selected countries. The boxplots show the second and third quartiles in the shaded areas and the whiskers extend to 1.5 times the interquartile range for the selected countries across the 30 years of weather conditions.

Conventional generators see lower running hours with increased year-to-year variability, implying more challenging financial conditions under energy-only markets. Thus, for these generators to remain financially sustainable, revenues may need to be preserved or given more stability with additional market designs or policies. This may prove pivotal for maintaining security of supply, as these generators mitigate many of the integration challenges associated with increased penetrations of VRE (Flynn et al., 2017, Eirgrid, 2017). Alternatively, more storage may assist with these challenges, or more transmission coupled with greater heterogeneity in where VRE is located (Grams et al., 2017).

5.5.3. Variability of CO_2 Emissions

Increased volatility in the operation of conventional fossil-fuelled generation yields a corresponding volatility in CO_2 emissions. Total European CO_2 emissions vary by up to 9% from the long-term average in the RE>60% scenarios depending on wind and solar resource availability – whether a given year had 'good' or 'bad' weather. In the 2015 system, this difference was 2%. The corresponding Europe-wide maximum variation in VRE power output is around 10% of average total VRE generation for all scenarios considered. With greater penetrations of VRE, the magnitude of this variability increases dramatically. In the 2015 system simulation, it represented 1% of total electricity demand and rose to 4% of total electricity demand in RE>60% scenarios. Figure 5.4 illustrates the variability in annual emissions intensity at a country level in both magnitude and as a percentage of average emissions intensity for two scenarios with contrasting ambition, demonstrating that emissions saved by VRE vary substantially depending on the sample year considered. Clearly visible in Figure 5.4 is that while the magnitude of emissions variability decreases in many countries, the percentage variability of CO_2 emissions intensity increases across the board.

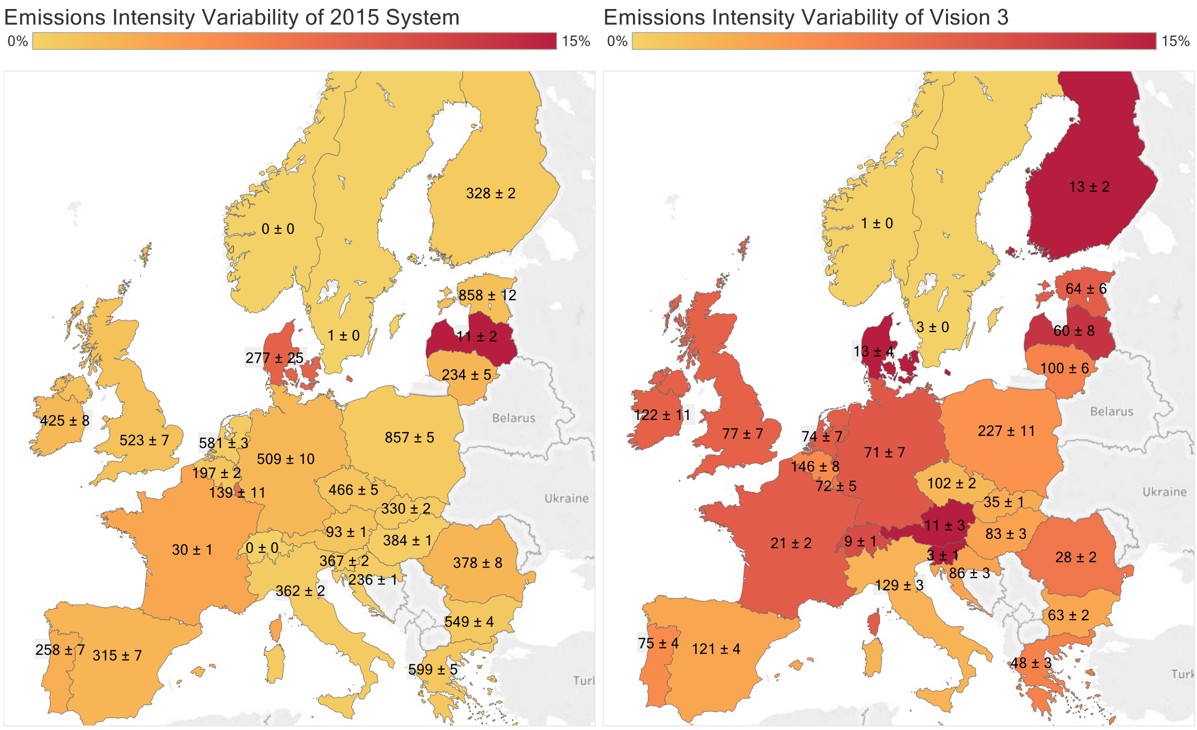


Figure 5.4: Variability of electricity CO_2 emissions intensity by country for the 2015 System and Vision 3. For both diagrams, the text on each country describes the mean emissions intensity followed by the standard deviation in kg/MWh over the course of all 30 weather years. The colour scale indicates the coefficient of variation for emissions intensity in each country.

Figure 5.5 demonstrates the impact of VRE output on the carbon intensity of electricity generation for selected countries which represent 40% of European electricity demand. Its left side shows the marginal CO_2 emissions intensity reduction from VRE for all scenarios, determined as the gradient of total national emissions intensity against total national percentage share of VRE output over all simulated weather years. This can be interpreted as the reduction in emissions intensity achieved by an increase of one percentage point in VRE penetration. The right-hand portion of Figure 5.5 displays the emissions intensity of generation for the EU Reference scenario.

In general, the marginal carbon reduction from renewables decreases as their penetration increases, as the low-hanging fruit (coal) becomes exhausted. Inter-annual variability of emissions intensity also decreases in magnitude with decarbonisation ambition but increases as a proportion of overall emissions, as shown in Figure 5.4. The marginal CO_2 emissions intensity reduction metric yields insights into where decarbonisation efforts could be focussed to maximise reductions in emissions intensity. The impact of VRE is greatest in Poland (out of the large countries plotted) due to its heavy reliance on coal, thus a 1 percentage-point absolute increase in VRE penetration yields a minimum 7kg/MWh reduction in grid carbon intensity. In contrast, Denmark has much higher VRE penetrations and thus less capability to decarbonise further using VRE. This analysis could help guide investments in new VRE capacity to be more efficient at carbon mitigation, and in greater interconnection between countries to limit their reliance on carbon-intensive generation.

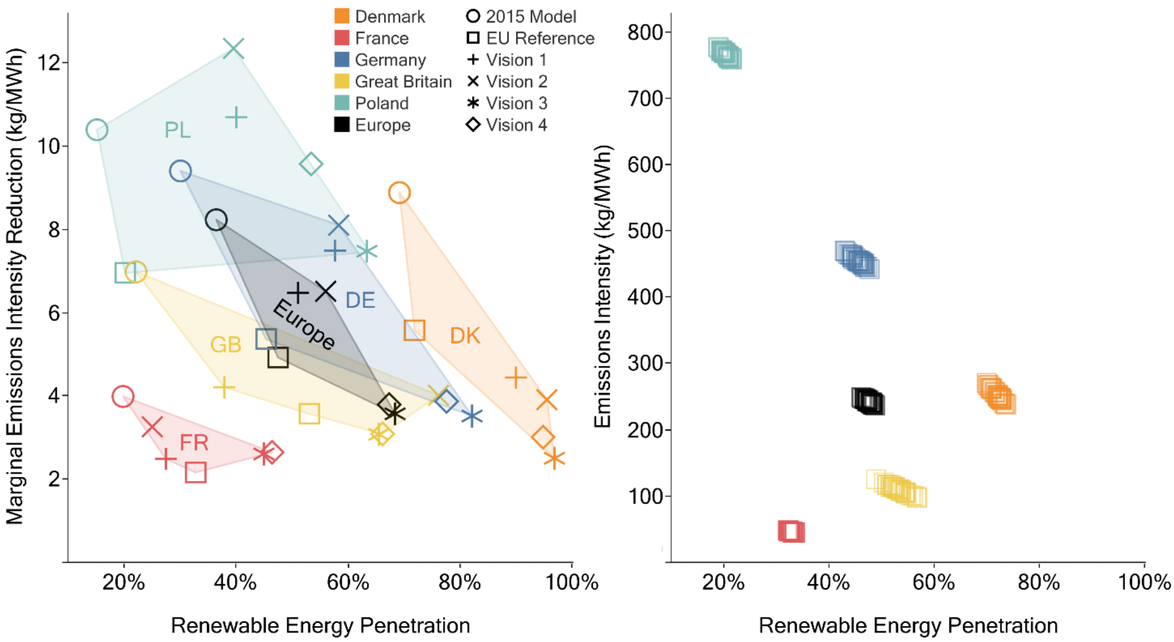


Figure 5.5: Marginal reduction in emissions intensity for a 1% increase in VRE penetration for all scenarios averaged across all weather years, and average emissions intensity in the EU Reference scenario for a selection of countries across all weather years. The average carbon intensity of electricity decreases marginally during years with higher VRE resource, with ±5% variation from across 30 years averaged over the five countries shown in Figure 5.5 for the EU Reference scenario. This inter-annual variability differs strongly between countries due to their generation mix and resulting exposure to VRE variability.

5.5.4. Curtailment of VRE and Interconnector Flows

Curtailment, the limiting of power output, is a method of regulating substantial amounts of VRE power in power systems. Situations that result in curtailment include limited transmission capacity, an oversupply of VRE and inflexible baseload generation. There is a strong correlation between VRE penetration and curtailment, with near-linear growth above 20% VRE penetration (as shown in Figure 5.1) and 50% total renewable energy penetration. In our model, curtailment may be caused by operational constraints on generators (minimum stable levels, minimum up and down times), by constraints ensuring demand is met, and by interconnector flow limits between countries. In common with MacDonald et al. (MacDonald et al., 2016) we do not consider pumped hydro or battery storage capacity. However, our curtailment levels should still be considered a lower bound, since our model operates under perfect market conditions and does not consider localised network or generation constraints, all of which would lead to greater levels of curtailment. For context, Germany and Britain experienced 5–6% curtailment of wind in 2015, with penetration levels of 12–13% (Joos and Staffell, 2018).

Analysing curtailment at a European level masks the uneven distribution and inter-annual variability of curtailment at a country level. Figure 5.6 presents this country-level variability across weather years for a selection of countries with substantial levels of VRE curtailment. In Vision 3, Germany experiences the greatest levels and variability of VRE curtailment, ranging from below 6% to above 10% annually depending on the year, in contrast to the 4.3%±1.2% (51±15 TWh) at the European level.

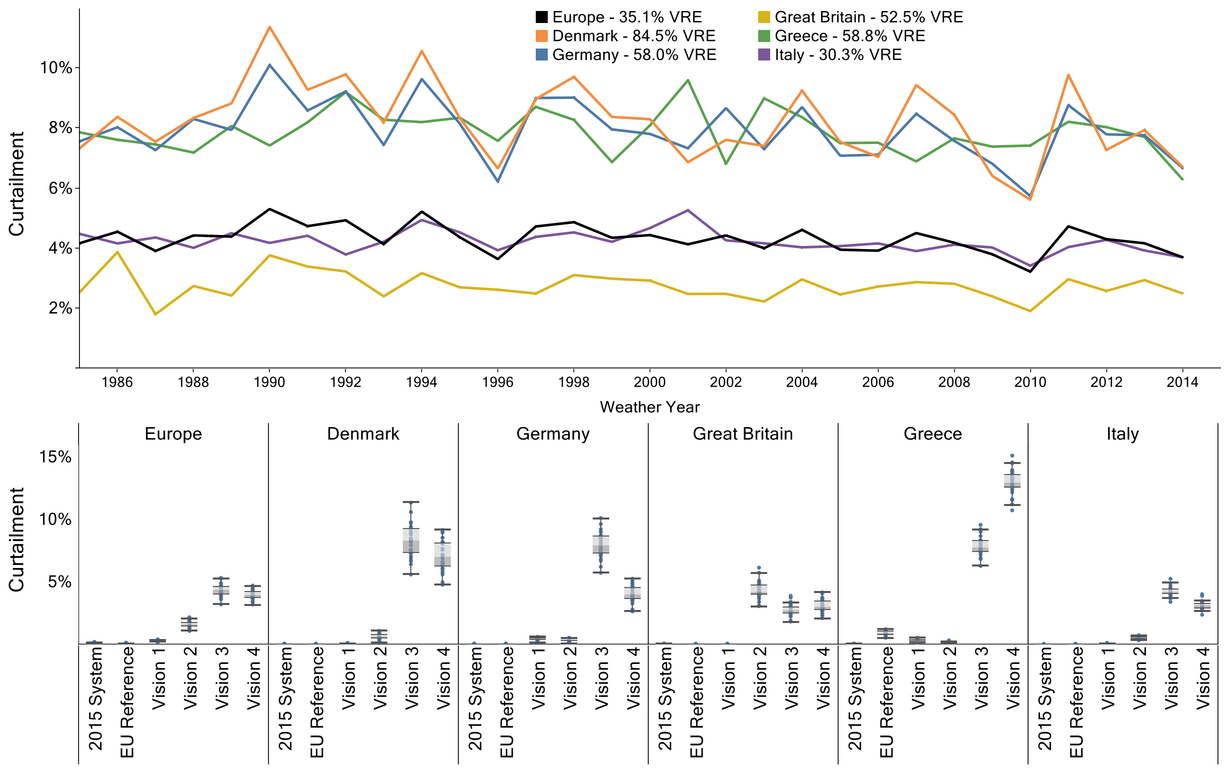


Figure 5.6: Country-level variability of curtailment of VRE across weather years. The top panel shows selected countries in Vision 3 with high levels of curtailment. The bottom panel shows boxplots summarising these countries within each scenario. The boxplots show the second and third quartiles in the shaded areas and the whiskers extend to 1.5 times the interquartile range for the selected countries across the 30 years of weather conditions.

While Germany has high levels of curtailment, its neighbour Poland has none. Poland imports substantial amounts of VRE but generates comparatively little. Its resulting carbon-intensive generation (see Figure 5.5) implies a high marginal emissions intensity reduction potential.

Interconnection is a valuable asset for managing large shares of VRE, with total interconnector flow increasing by up to 80% in RE>60% scenarios relative to the 2015 system. This increased flow corresponds to greater interdependency between countries and allows an increasingly variable electricity supply to meet demand across broader areas to mitigate supply-demand mismatches. Interconnector congestion directly restricts the flow of electricity and leads to increased emissions and curtailment of VRE. With targeted infrastructure investment, interconnection capacity could be increased to minimise these factors. As identified in Table 5.2, inter-annual flow volatility remains relatively static on interconnector lines and in terms of the overall international flow of electricity. Coupled with a substantial increase in overall interconnector flow, this should continue to provide stable revenues for interconnector operators.

5.6. Discussion

Our long-term multi-scenario analysis of European variable renewable power generation maps out for the first time the impacts of long-term weather variability on the operation of a continental power system and how this varies with decarbonisation ambition.

Increased penetration of weather-dependent renewables leads to increased variability in system operation, with five-fold growth in the inter-annual variability of CO_2 emissions and total generation costs from the 2015 baseline scenario to the most ambitious 2030 vision. This corresponds to an increased variability in the operation of conventional generators, predominantly those providing baseload, which act to balance out resource availability. Many of these trends can be approximated by simple linear functions of VRE penetration. This allows rapid yet accurate back-of-the-envelope calculations for the impact of renewables deployment in the absence of computationally intensive modelling. Analysis derived from a single or small number of years data would fail to capture such variability. Thus, estimating decarbonisation achievement based on such data is flawed. We find that single-year studies could yield results that deviate by as much as ±9% from the long-term average at a European level and even more at a country level. This also implies that when measuring progress towards countries' decarbonisation targets on a year-by-year basis, weather variability must increasingly be considered as more VRE generation is deployed.

Inevitably, some work must continue to use single-year data due to data availability or computational tractability. Our analysis of three decades of data reveals that the weather years 2012 and 1989 were the most representative for considering power system operation at a European level. This was determined by analysing the variability of the metrics considered in this chapter, which for these years were within ±1% of the 30-year average in relative terms (see Appendix B for further information). The years 1990 and 2010 were shown to exhibit the greatest deviation, with our various metrics deviating by ±6% from the long-term average.

A near doubling of interconnector flow (in terms of total international electricity flow) between 2015 and 2030 under ambitious scenarios quantitatively demonstrates an increased interdependency under deep decarbonisation of the European power sector. Such interdependency and integrated pan-European operation enable the minimisation of operation costs, CO_2 emissions and variable renewable curtailment. The latter increases linearly beyond 20% penetration of VRE and is an inherent part of a highly variable renewable power system. This should not necessarily be thought of purely as operational inefficiency, but rather considered in the context of the costs of additional transmission infrastructure and storage that would be required to make use of curtailed energy. Some curtailment should be acceptable in highly-renewable power systems, and the specific level depends on the interplay between the lost value of energy and these additional infrastructure costs. Greater interconnection between countries, the emergence of significant quantities of energy storage (either through dedicated stationary storage or smartly-controlled electric vehicle fleets) could facilitate higher shares of renewable energy; as could the emergence of new weather insurance products (e.g. hedging between wind and gas generators to offset revenue risks).

Achieving a decarbonised power system is not without challenges, and this chapter maps out a variety of key issues associated with power system decarbonisation. However, much remains to be studied and more questions to be asked in order to plan a robust decarbonisation of the European power system. For policy developments to be verifiable, interoperable and representative of the meteorological dependency of decarbonised energy systems, they must be based on open modelling analyses that utilise common long-term datasets, such as those used in this work (Pfenninger et al., 2017, Pfenninger, 2017b).

To this end, the model and all supporting datasets underpinning this chapter have been made openly available so as to provide the power systems research community with tools to further explore these important issues.

5.7. Methods

Here we describe the power system scenarios that were considered, and the methodologies underpinning the development of the power system dispatch model used and the wind and solar PV profiles used.

5.7.1. Scenarios Considered

A total of six different power system scenarios were analysed. The 2015 scenario was developed based on historic electricity demand from ENTSO-E for 2015 and installed capacities based on the European Commission's EU Reference Scenario (European Commission, 2016b) 2016 results calibrated for the year 2015. The policy scenarios are all for the year 2030, based on the EU Reference Scenario (European Commission, 2016b) and the ENTSO-E Visions (ENTSO-E, 2016b). The EU Reference Scenario projects how the European energy system may evolve to 2030 based on business-as-usual assumptions, including full implementation of EU energy and climate policies adopted by December 2014 (for the EU Reference Scenario model, Swiss and Norwegian generation mixes were developed based on ENTSO-E and national strategy documents as they were not part of the EU Reference Scenario (Agora, 2015, ENTSO-E, 2016b)). The ENTSO-E Visions encompass a broad range of possible futures that span a broad range of ambition in terms of the achievement of the sustainability goals within the EU 2050 Roadmap. The four Visions provide the envelope within which the future could plausibly occur, but strictly do not act as upper/lower bounds or have a probability of occurrence attached to them (ENTSO-E, 2016b). These scenarios informed the electrical load profiles, the efficiency of power generation, and installed generation mix by fuel type in the models constructed. The levels of interconnection used between countries for all 2030 scenarios was informed by those projected within the ENTSO-E's scenario development report for the year 2030 (ENTSO-E, 2016b). For the 2015 scenario, the values for 2020 from the same report were used but adjusted to reflect projects that were not yet completed by 2015 in line with the ENTSO-E ten-year network development plan (ENTSO-E, 2016a). In this analysis, to account for the associated costs of interconnector flows in terms of the economic dispatch, wheeling charges of €4/MWh were applied to the model for all interconnector lines.

5.7.2. Modelling Framework

The software used to model the EU electricity market is the PLEXOS Integrated Energy Model (Energy Exemplar, 2018a), which is widely used for electricity and gas market modelling and planning. In this analysis, the focus is limited to the electricity system, i.e. gas infrastructure and delivery is ignored in these simulations. Within the electricity sector, the model optimises the dispatch of thermal and renewable generation, holding the installed capacity constant, subject to operational and technical constraints at hourly resolution. The model seeks to minimise the overall generation cost across the EU to meet demand subject to generator technical characteristics such as ramp rates, start costs, minimum up times etc. This includes operational costs, consisting of fuel costs and carbon costs; start-up costs consisting of additional fuel offtake and a fixed unit start-up cost. Model equations can be found in (Deane et al., 2014). In these simulations, a perfect day-ahead market is assumed across the EU (i.e. no market power or anti-competitive bidding behaviour, thus power station bid their short-run marginal cost) similar to Deane *et al.* (Deane et al., 2015d).

The models used in this work were developed using a soft-linking approach as applied to the results of energy systems models in (Deane et al., 2015b, Deane et al., 2015a, Deane et al., 2012, Collins et al., 2017a), whereby the results of of these models are studied using a dedicated power system model to simulate the operational unit commitment and dispatch of the system. The approach as applied in this work differs from that in previous studies in that it was applied to the results of scenario development by a transmission system operator to inform long-term transmission expansion in addition to those from an energy system model. However, given this approach extracts results and uses them as a starting point for further analysis, the application of the approach was the exact same. Due to the scale of the European power sector and challenges with acquiring granular technical characteristics for the ~10,000 power stations across 30 countries (Green and Staffell, 2016), standard generator classes for 15 modes of generation per node were used with homogenous characteristics such as max capacities, ramp rates, minimum up & down times, forced outage & maintenance rates and startup & shutdown costs. Each of these technology types has their own standard efficiency which themselves differ by country for the years 2015 and 2030 respectively based on values used in for these technologies in the EU Reference Scenario for these years. The standard generator characteristics were the same as those employed in earlier chapters 3 and 4. A summary of the main generator characteristics used in this study is available in Table 3.3 of chapter 3. The resulting market price is defined as the marginal price (note that this is often called the shadow price of electricity) at country level and does not include any extra revenues from potential balancing, reserve or capacity markets or costs such as grid infrastructure cost, capital costs or taxes. The models were not constrained for stability issues related to high levels of non-synchronous generation that have been shown to impact the frequency, voltage, transient and small signal stability of the power system (Flynn et al., 2017). It was assumed that such operational constraints could be met in ancillary services markets with negligible impact on system operation.

5.7.3. Load Profiles

Each scenario had a unique electrical load profile for each country. For the 2015 system model, historic demand profiles for this year were used as provided by ENTSO-E. For modelling the EU Reference Scenario 2016, the overall energy use was detailed in the results but the profile was not. Thus, it was scaled to 2030 based on the historic hourly 2012 profiles with a peak scaling of 1.1 using PLEXOS which increased peak load by 10% compared to 2012 levels. For the models of the ENTSO-E four 2030 Visions, the hourly load profiles of each scenario were used without the need for adjustment.

5.7.4. Hydro Profiles

Hydro generation is modelled as individual monthly constraints via generation profiles provided by ENTSO-E for each individual Member State of the EU28 and Norway for the year 2012. These monthly constraints are decomposed to hourly profiles in the optimization process.

5.7.5. Wind and PV Profiles

We use the Renewables.ninja PV and wind simulation models (Pfenninger and Staffell, 2016, Staffell and Pfenninger, 2016) to generate hourly time series of wind and PV generation aggregated to country levels for 30 historical weather years, from 1985 to 2014.

The historical weather conditions come from the NASA MERRA-2 reanalysis (Gelaro et al., 2017). While satellite irradiance measurements are an alternative source of data for PV simulations (Pfenninger and Staffell, 2016), MERRA-2 is used for both PV and wind in order to maintain internal consistency of the dataset and because it exhibits better long-term stability over the three decades considered.

For wind, we extract wind speeds at 2, 10 and 50 metres above ground. For PV, global horizontal irradiance and direct normal irradiance are estimated from surface and top of atmosphere incident shortwave flux variables. Surface temperature is used to compute temperature-dependent panel efficiency. We model individual wind farms (~10,000 across Europe), considering the specific location and characteristics of each farm (turbine model and hub height). Missing data is inferred using multivariate regression[4].

There is no consistent and accurate spatially resolved dataset all existing European PV installations. For PV, we therefore simulate an installation in each MERRA-2 grid cell (assigning these cells to countries and with each country scaled to its installed capacity). We assume probabilistic panel alignment and inclination, sampled from normal distributions fitted to observed panels installed across Europe (Pfenninger and Staffell, 2016). We modelled azimuth as 180 ± 40 degrees (clipped to [0, 360]), and tilt as latitude ± 15 degrees (clipped to [0, 90]).

For each of the four visions, solar power is scaled to the national totals accordingly; while the wind fleet is based on the commercial planning pipeline currently in place. Existing farms are assumed to all still be in existence, then new farms are added until the capacity specified by the scenario is reached. Capacity is added by first drawing randomly from farms under construction, then those with approved planning permission, and finally those earlier on in the planning pipeline. For these planned future wind farms, the anticipated hub height, technology and location are accounted for (Staffell and Pfenninger, 2016). Thus, the future time series of wind output account for anticipated technological progress out to 2030.

[4] For example, if the hub height of a particular farm is not known it will be inferred based on the turbine capacity, year of installation and the country it is located in.

Chapter 6: Planning the European Power Sector Transformation: The REmap Modelling Framework and its Insights

6.1. Abstract

IRENA's renewable energy roadmap (REmap) programme enables the assessment of the renewable energy potential at sector and country level for the year 2030 based on a unique methodology that has been applied to 70 countries. This chapter presents findings of REmap for the European power sector where the REmap methodology is complemented with a power system dispatch model, called the REpower Europe model. Results show that in 2030 under REmap, gross electricity demand in the EU-28 can be met with a renewable energy share of 50% and a variable renewable energy (VRE) share of 29%. This would achieve a 43% reduction in the EU power sector's carbon dioxide (CO_2) emissions relative to 2005 levels. Although achieving higher renewable electricity shares by 2030 is effective in reducing emissions, significant operational challenges would be encountered to realise the potential identified in REmap. Attention needs to be paid to interconnector congestion, curtailment of VRE and operation of dispatchable generators by power system planners to achieve this potential. While the strength of the REmap approach is transparency that allows engagement with energy planning stakeholders, the key to its effective application is the right balance of model complexity and operational ease. This chapter shows the insights that can be gained by leveraging the approach and that valuable policy insights are drawn by using a suite of modelling approaches.[1]

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[1] Published as: COLLINS, S., SAYGIN, D., DEANE, J. P., MIKETA, A., GUTIERREZ, L., Ó GALLACHÓIR, B. & GIELEN, D. 2018. Planning the European power sector transformation: The REmap modelling framework and its insights. Energy Strategy Reviews, 22, 147-165.

6.2. Introduction

In early 2014, the European Union (EU) released its 2030 climate and energy framework package. The framework sets three key targets for the year 2030: 1) 40% cut in greenhouse gas (GHG) emissions compared to 1990 levels, 2) at least 27% share of renewable energy in gross final energy consumption (GFEC), and 3) at least 27% energy savings compared with the business-as-usual scenario (European Council, 2014). These targets represent an important increase compared to the 20-20-20 targets to be achieved by 2020.

While the proposed targets are EU-wide, the specific role of country, sectors and technologies are not yet determined. In understanding how such regional targets can be operationalized at these levels, the International Renewable Energy Agency's (IRENA) global renewable energy roadmap (REmap) programme with a 2030 outlook is a useful tool (Kempener et al., 2015, Saygin et al., 2015). In Europe, at the time of writing, 11 Member States that represent more than 80% of EU's total final energy demand are part of IRENA's REmap programme. These countries are Belgium, Cyprus, Denmark, France, Germany, Italy, Poland, Spain, Sweden, the Netherlands and the United Kingdom[2].

The methodology underpinning the REmap analysis is a relatively simple accounting framework that allows national experts to identify additional renewable energy technology options (called "REmap options") beyond existing renewable energy expansion plans up to 2030 based on current policies and policies under consideration, referred to as the "reference case". To ensure an accurate representation of country-specific challenges, this analytical framework is based on a bottom-up analysis of renewable energy potential in individual countries. To date, 70 countries which represent more than 90% of the total global energy demand are participating in IRENA's REmap programme. The unique approach of REmap allows the analysis to be applied to all countries in the world in a comparable way and it provides a transparent way to communicate results with the national experts and other stakeholders.

[2] At the time when the power system model presented in this chapter was developed, ten REmap countries (excluding Spain) had a complete REmap analysis. As the model considers two scenarios (a Reference scenario and REmap scenario), a "quick-scan REmap" power system scenario was developed for the remaining 18 countries.

There are advanced tools available that enable a detailed analysis of the evolution of energy systems, such as long-term energy system optimization models and integrated assessment models (Pfenninger et al., 2014). These models are more sophisticated than the REmap tool and their results were contrasted with REmap by Kempener et al in (Kempener et al., 2015). Their work identified several key insights provided by such long-term modelling tools that are not provided by the REmap approach: the transmission and distribution requirements for higher shares of renewables in the energy system, system constraints, path dependencies or competition for resources that affect both the potential and costs of additional renewable energy deployment. REmap as a tool is better suited to high-level energy system assessment rather than detailed national renewable energy planning and it requires additional checks to compensate for reduced detail on how technologies in an energy system interact with each other. With complementary approaches that overcome its limitations, policy-making can be better informed.

In transitioning to a low-carbon energy system, the power sector will be of paramount importance. The sector is already experiencing a rapid growth in renewable energy capacity in recent years. Worldwide, since 2012, the share of renewable energy in new capacity additions has been increasing and in both 2015 & 2016 renewables were in excess of 50% of total new capacity additions (Frankfurt School-UNEP Centre/Bloomberg New Energy Finance, 2017). In the EU, of all the 24.5 gigawatts (GW) power generation capacity added in 2016, 21.1 GW was from renewables (WindEurope, 2017). For context, renewables accounted for 405 GW of a total installed generation capacity of 920 GW in the EU in 2016 (WindEurope, 2017). However, the sector remains a large emitter of carbon dioxide (CO_2) emissions. When achieving higher shares of renewable energy in the power sector, it is expected that a large share will originate from variable renewable energy (VRE) sources[3] (European Climate Foundation, 2010, European Commission, 2011, IEA, 2012b, Luderer et al., 2014). In the EU, the renewable energy share in the power sector reached 28.8% in 2015 out of which little over a fifth was from VRE sources (Eurostat, 2016b). The generation from these variable sources can be difficult to predict, intermittent and quite location

[3] VRE generation sources discussed in the context of this work consist of wind and solar PV generation only, which have far more variability in the short term than other renewable modes of generation such as hydro power.

specific. High proportions of VRE sources on the power system, therefore, have a substantial impact on the operation of the power system (Holttinen, 2004, Holttinen et al., 2009, IEA, 2012a, Eurelectric, 2011, Müller et al., 2014). This leads to challenges with regards to ensuring a reliable and adequate system in the long-term planning of the power sector (Pfenninger et al., 2014). This struggle is common to both the REmap tool and to long-term energy system planning models, but for long-term energy planning models, this has been an active area of research with a variety of methodologies having been developed to address this (Collins et al., 2017b, IRENA, 2017b).

The objective of this chapter is to provide policy insights regarding the implications of the power sector technology mix derived from REmap EU analysis for 2030 on the operation of the European power system. For this purpose, an EU power system model[4] (called "The REpower Europe model) has been developed that performs a dedicated hourly operational analysis of the European power sector by modelling economic dispatch assuming full implementation of the renewable energy technology potential according to the REmap findings. These results have been benchmarked against a similar simulation of the model for the reference case for 2030. This process allows for further, more detailed analysis to be performed by exploiting the added value that is brought by using a power system model with high technical and temporal resolution. This complementary approach enables generation of new results that add new insights to REmap findings. In particular, it quantifies levels of curtailment, electricity trade, interconnector congestion, wholesale market price changes, and effects on market clearing (e.g. merit order, marginal unit) and other metrics. The value of these additional insights is in the increased understanding of the robustness of a transitional low carbon electricity sector and in identifying challenges and operational concerns which may accompany that transition. While this analysis draws conclusions for policy making by linking two complementary approaches, it also thoroughly compares them by discussing their strengths and weaknesses. This is particularly important so as to gain more insight into the right balance of model complexity and operational ease.

The large synchronously interconnected nature of the European power system coupled with increased variability on the supply side will lead to the increased importance of

[4] Swiss and Norwegian power systems are also represented

interconnector flow in efficient and cost-effective power system operation. In a power system with high penetrations of VRE, the short-term ability to export and import electricity as required to mitigate the negative impacts of variability is an important consideration. This required the detailed REmap results to be analysed within the context of a wider European electricity model, even though the REmap analysis has only been completed for ten countries. In order to draw conclusions for the entire region, the REmap analysis was expanded to cover the remaining 18 EU Member States by developing an accelerated renewable energy scenario that builds on European Commission's EU Reference Scenario (European Commission, 2016b) (hereafter referred to as the EU Reference Scenario) which is a projection of where the current set of policies coupled with market trends are likely to lead.

The rest of the chapter is structured as follows: Section 6.3 introduces and describes the policy and modelling tools informing this analysis. Section 6.4 describes the methodology underpinning this analysis. Section 6.5 provides a detailed overview of the results of this analysis, providing a broad assessment of the power system developed under the REmap tool. Section 6.6 forms a discussion of the key results and the strengths and weaknesses of the REmap tool as well as the complementary model used for power dispatch. Section 6.7 synthesises the conclusions drawn in this work.

6.3. Policy and Modelling tools

This section explains the models and data sources that were used for the analysis. They include IRENA's REmap tool, PLEXOS Integrated Energy Model (see section 3.3.1) and the PRIMES model (see section 3.3.2) from which the EU Reference Scenario is derived that is used by European Commission to inform policy development. In this study, the installed capacity mixes and demand for power generation from the REmap analysis for 10 EU countries were used as an input. For the installed capacity mixes and demand for the remaining 18 EU countries, the EU Reference Scenario 2016 was used. The EU Reference Scenario 2016 assumes that legally binding greenhouse gas and renewable energy targets for 2020 will be achieved and that the policies agreed at EU and Member State level up until December 2014 will be implemented. This data from the REmap tool and the EU Reference Scenario are then used as input for the subsequent analysis of power systems operation using a dispatch model, the REpower Europe model, built using PLEXOS. The solver used in this work for the PLEXOS simulations was Xpress-MP (FICO, 2018).

6.3.1. REmap Tool

REmap is a tool that helps to define renewable energy technology options across all energy sectors for decision-makers to consider. The process is to first collect data from countries about their national energy plans and goals, and the next step is to produce a national baseline for renewable energy deployment for the period between 2010 and 2030. This is called the Reference Case. Subsequently, technology pathways that reap the rewards of the reasonably optimistic potential of renewable energy technologies beyond the Reference Case are prepared, these are the REmap options. Reference Case and REmap options combined yield the "REmap" case. This process is illustrated in Figure 6.1. REmap options are customised for specific countries and sectors and aim to close an important knowledge gap for many countries by helping policymakers gain a clearer understanding of the opportunities that lie before them. These options are determined through consultation with experts from countries and/or based on studies that provide an accelerated renewable energy deployment outlook. Once the REmap Option is estimated, a conventional technology that could be substituted is selected in consultation with the national experts. This is based on the policy choices of the countries (IRENA, 2016).

The methodology of REmap is different from other scenario studies and modelling exercises as the cornerstone of the approach is co-operation and consultation with countries. Key to this is the transparency and simplicity of data and analysis. IRENA co-operates with the nominated country experts in developing the Reference Case and the REmap options. IRENA has developed a spreadsheet tool that allows country experts to evaluate and create their own REmap analyses. These are clear and dynamic accounting frameworks to evaluate and verify Reference Case developments and REmap options within a country (IRENA, 2016). The REmap methodology has been discussed in detail in (Saygin et al., 2015, IRENA, 2016).

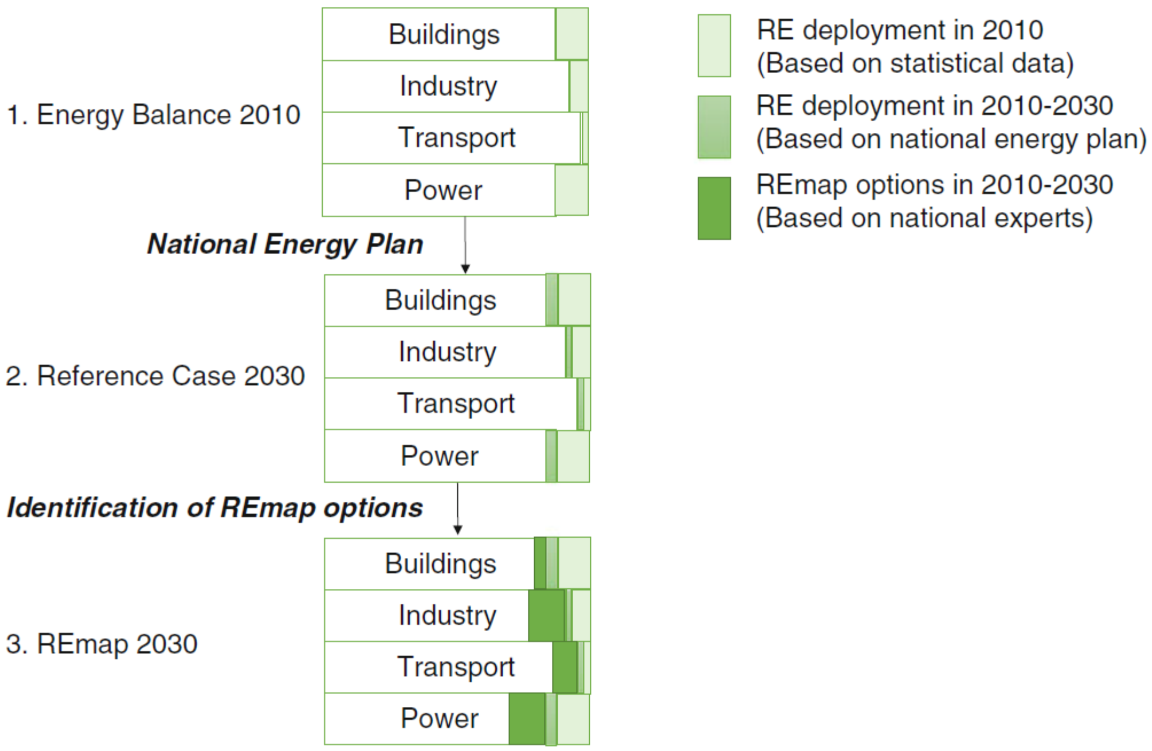

Figure 6.1: The analytical steps to develop the REmap analysis (Kempener et al., 2015)

6.4. Methodology

6.4.1. Modelling Approach

The methodology applied in this work is a soft-linked methodology as described in section 3.4.1 of chapter 3.

The REpower Europe dispatch model is run for two distinct scenarios for all 28 EU Member States, one is called the Reference scenario (not to be confused with the European Commission's EU Reference Scenario) which shows what existing and planned policies will deliver, and the second is called the REmap scenario which is a scenario that considers accelerated uptake of renewable energy technologies. Both scenarios differ in terms of electricity demand (with the REmap scenario having increased electrification of transport and heating) and installed electrical generation capacity. Further details regarding the application of the approach in this work is detailed in sections 6.4.3, 6.4.4, 6.4.5 and 6.4.6.

6.4.2. Development of REmap and Reference Scenarios for the REpower Europe Model

Figure 6.2 illustrates the Member States for which a full REmap assessment has been completed (orange), REmap engagement was in progress at the time of writing (red) and countries which are yet to engage with REmap (blue). For the 18 Member States yet to have completed a full REmap assessment (the Member States highlighted in red and blue), an alternative approach was taken to develop representative generator portfolios (i.e. installed generation capacity mix) for both REmap and Reference scenario simulations. For the REpower Europe model, power system representation in Switzerland and Norway were the same for both REmap and Reference scenarios and based on the conservative “Slowest Progress” Vision 1 scenario of the European Transmission system operator’s, ENTSO-E’s, scenario development report used to inform their 2016 ten-year network development plan (TYNDP) (ENTSO-E, 2016a). Installed capacities of pumped hydro storage facilities across the EU-28, Norway and Switzerland were derived from open source resources developed by FRESNA - FIAS Renewable Energy System and Network Analysis (Hörsch and Hofmann, 2017) and the Joint Research Centre of the European Commission (Quoilin et al., 2017).

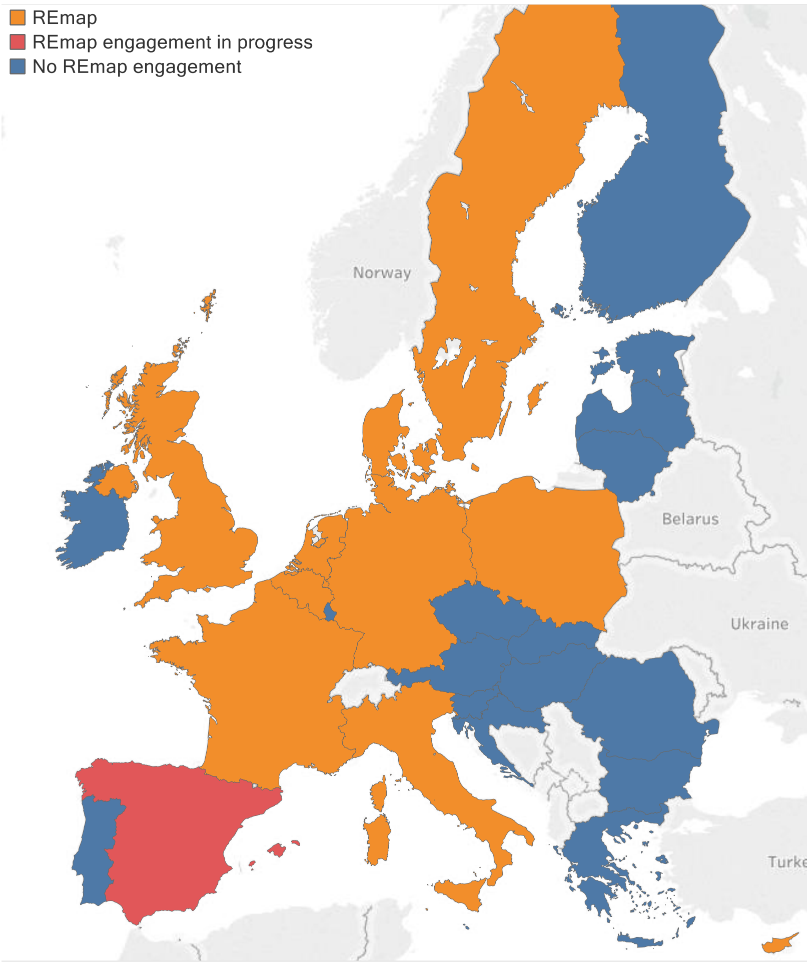

Figure 6.2: Participation of EU Member States in IRENA's REmap programme

6.4.2.1. Scenario Development for 10 EU Member States That Have Completed a Full REmap Assessment

For brevity, these Member States are referred to as the "REmap countries" hereafter. For both the REmap and Reference scenarios, power generation capacity mix and total annual electricity demand for these Member States were informed by the outputs of each respective REmap assessment. Electricity demand in both REmap and Reference scenarios represent approximately 72% of EU electricity demand in 2030 in this work. For these ten countries, the Reference scenario is represented either by the National Renewable Energy Action Plan prepared in accordance with the EU Renewable Energy Directive (2009/28/EC) (European Parliament and Council, 2009a) or, if available, by the most recent national energy outlook provided by the Member State experts (IRENA, 2016, IRENA, 2015b, IRENA, 2015a). REmap options were created by IRENA in close cooperation with the country experts and were generally based on outlooks that cover a more aggressive representation of renewables deployment.

6.4.2.2. Scenario Development for the 18 EU Member States Yet to Complete a Full REmap Assessment

For brevity, these 18 Member States are referred to as the "REmap Brief countries" hereafter. For the Reference scenario simulation, the total electricity demand for these REmap Brief countries was derived from the EU Reference Scenario 2016 (European Commission, 2016b) for the year 2030. For the REmap scenario, the annual electricity demand was increased beyond these levels to account for increased electrification of heating and transport in line with a REmap assessment completed by IRENA identifying such potential. The annual level of demand for all Member States for both REmap and Reference scenarios can be seen in Appendix C.

For the Reference scenario, the installed generation mix for these Member States was based on the EU Reference Scenario 2016 for the year 2030 (European Commission, 2016b).

For the REmap scenario, the installed generation mix from the EU Reference Scenario 2016 for REmap Brief countries was altered to generate a representative increased renewable uptake scenario akin to that developed for the ten REmap countries.

The process for generating installed capacity mix for REmap Brief countries for the REmap scenario is as follows:

(i) An initial estimate of REmap options is made for the 18 REmap Brief countries based on their resource availability and installed capacity in 2030 under the Reference scenario. REmap options in this instance covered only wind and solar PV and their installed generation capacity were scaled up based on an assessment of their respective national potential. This increase in the total VRE capacity between the REmap and Reference scenarios is comparable to that projected in the ten REmap countries.

(ii) After this initial assessment of the potential, an iterative process was followed that altered the installed capacity of these VRE sources in these 18 countries. This process involved the simulation of an EU-28 power system dispatch model in PLEXOS for this initial and each subsequent REmap scenario developed.

Installed capacities of VRE in REmap Brief countries were subsequently revised in countries in an iterative process in line with modeller observations. The modeller observations that informed this process were instances of curtailment of variable renewable power, interconnector congestion and emissions intensity of generation. This is to say that when operational challenges arose under the simulation of the REmap scenario or greater decarbonisation seemed reasonably practicable, installed capacities of VRE were revised in these REmap Brief countries.

(iii) The increased renewable energy capacity introduced under the REmap scenario reduces the need for non-renewable energy capacity from the Reference scenario to supply the same amount of electricity. For the 18 REmap Brief countries, a capacity credit methodology developed by the IEA (OECD and IEA, 2015) was implemented to determine the level of fossil fuel capacity which could be removed from the generation mix with the introduction of additional variable renewable energy capacity in the REmap scenario.[5] This involved the substitution of the most carbon-intensive fossil fuel electricity generation capacity.

While simplified, this process facilitated the development of a highly renewable power sector scenario for the EU that is broadly representative of those developed in the REmap countries. Full details of the final installed capacities used in this work are detailed in Appendix C.

6.4.3. Model Generator Portfolio Development

Both REmap and the EU Reference Scenario provide the power generation capacity mix by technology between 2010 and 2030 for each Member State, as shown in Appendix C. These results for each Member State are detailed and broken down into various technologies of generation. For the same reason as outlined in earlier chapters, in the REpower Europe model, each country's generator portfolio is represented by standard generators with

[5] For the REmap countries, close collaboration with country experts facilitates the careful substitution of dispatchable fossil fuelled generation with variable renewable sources.

standard characteristics (max capacity, min stable levels, ramp rates, maintenance rates, forced outage rates, start costs etc). The standard generator characteristics were the same as those employed in earlier chapters 3, 4 and 5. A summary of the main generator characteristics used in this study is available in Table 3.3 of chapter 3.[6] Each disaggregated generation capacity was made up by many identical generators that sum to the total installed capacity as split by fuel type in the aggregate generation mixes. Average heat rates (an indicator to express the efficiency of electricity generation) for the various types of power plant in the model are defined at country level and are as they appear in the EU Reference Scenario 2016 results (European Commission, 2016b). The efficiency of gross thermal power generation by Member State is shown in Appendix C.

6.4.4. Interconnection

Interconnection capacity assumptions were based on (ENTSO-E, 2016b) and were identical to what was implemented in chapter 5 for the 2030 simulations, see section 5.7.1 for further information.

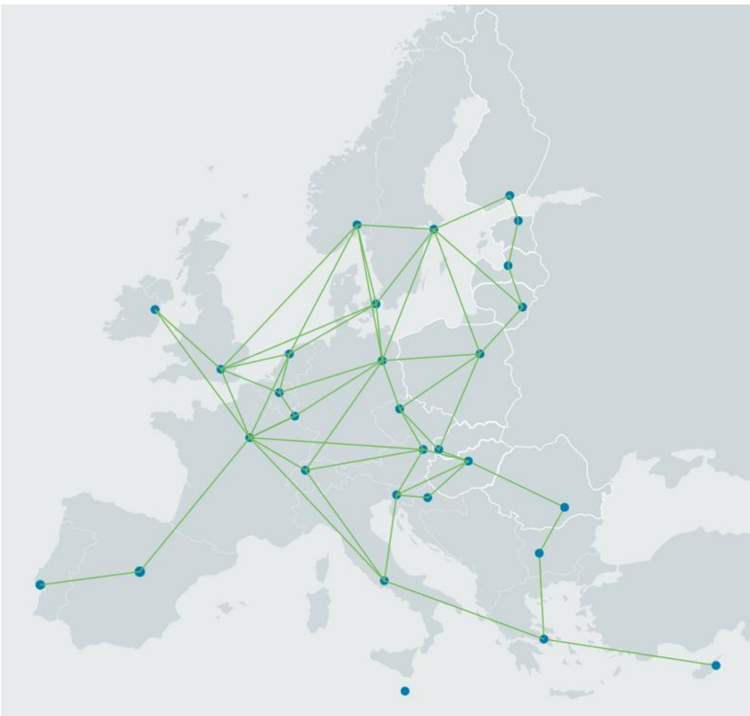

Figure 6.3: Interconnection as modelled within the REpower Europe model (IRENA and European Commission, 2018)

[6] Smaller standard generation units were used for power system representation in Cyprus and Malta to better represent these smaller power systems.

6.4.5. Demand

Historic hourly demand profiles from ENTSO-E for the EU in the year 2012 (ENTSO-E, 2012a) were used and linearly scaled to 2030 levels with a peak scaling of 1.1 which increased the peak demand in 2030 by 10% compared to 2012 levels. This is broadly in line with the average increase in peak demand in the 2030 scenarios considered for the ENTSO-E Scenario Development Report 2016 that informed the ten year network development plan (ENTSO-E, 2016b). Cogeneration was captured within the model through the use of minimum annual generation levels based on the cogeneration requirement outlined in REmap & the EU Reference Scenario respectively. The sum of this total electricity supply from cogeneration represents 12% of EU-28 final electricity demand and of this cogeneration, approximately 80% is fuelled by fossil fuels. The fuel mix of this cogeneration was based upon historical consumption for cogeneration from the IEA for the year 2012 (IEA, 2014), thus making it conservative.

6.4.6. Generation Profiles of Variable Renewable Generation

Hourly wind generation profiles were used in the REpower Europe model for each Member State derived from the EMHIRES data set developed by the Joint Research Centre of the European Commission that models how hourly energy production from installed wind farms in Europe have produced in every hour over the course of the past 30 years (Gonzalez-Aparicio et al., 2016). The profiles provided by the EMHIRES dataset are at a national scale based on 2015 installed capacities, thus to account for anticipated technological improvements and evolution of wind farm locations out to 2030 they were scaled to align with national level capacity factors as anticipated by the EU Reference Scenario results for 2030.

Hourly solar generation profiles were developed for each Member State considered in this work using NREL's PVWatts® Calculator web application (Dobos, 2013). The profiles created were then normalised with the generation capacity for each Member State. The hydro generation profiles that were used in this work were at a monthly resolution and derived using historic generation profiles provided by ENTSO-E for each individual Member State of the EU-28, Switzerland and Norway.

6.4.7. Prices of Fuels and CO_2 emissions

Fuel prices are for the 2030 target year as per IRENA analysis and unlike chapter 3, 4, and 5 they differ by Member State. These were based on local historic fuel prices and scaled out to 2030 based on fuel pricing trends for coal, oil and natural gas as projected by the EU Reference Scenario (European Commission, 2016b). These are available in Appendix C. Biomass and bio-methane fuelled generators were priority dispatched in the model simulation which means that their true fuel cost did not feature in the dispatch. This is because they are not typically market driven and their actual fuel price projection would see them fall unrealistically low in the merit order. The carbon price used in this analysis is €25 per tonne of CO_2.

6.5. Results

A comparison of results of the REpower Europe model simulations of the REmap scenario to those of the Reference scenario facilitates analysis of the operational impact of realising the REmap findings for EU's power sector in the year 2030. Table 6.1 provides an overview of the results of both simulations to facilitate discussion.

Table 6.1: Overview of the REpower Europe model results for the EU-28 for both REmap and Reference scenarios in 2030

	REmap scenario	**Reference scenario**
Total CO_2 Emissions	654 Mt	759 Mt
Emissions Intensity	177 $kgCO_2$ /MWh	219 $kgCO_2$/MWh
Contribution of Wind and Solar PV Generation	29.0%	21.3%
Total Renewable Electricity Generation	50.2%	41.1%
Total Interconnector Flow[7]	583 TWh	567 TWh
Average Interconnector Congestion[8]	3572 hrs/year	3428 hrs/year
Average Interconnector Capacity Factor[9]	54.6%	53.2%
Total Curtailment of Wind and Solar PV Generation	0.8%	0.6%

REpower Europe model simulation results show that the REmap scenario is effective in the decarbonisation of the power sector by achieving a 14% reduction in overall CO_2 emissions compared to the Reference scenario and a 43% reduction relative to 2005 levels (European Environmental Agency, 2016a) whilst respecting many operational constraints of the power system. This is achieved by solely altering the generation capacity mix (without additional flexibility measures) despite an overall increase in electricity demand while maintaining a similarly low level of wind and solar PV curtailment of 0.8%. Interconnectors are an important source of flexibility in the model by allowing the import and export of

[7] This is the sum of absolute flows on interconnector lines independent of direction of flow.

[8] Average congestion refers to average number of hours at which an interconnector is operating at full capacity. If an interconnector were to operate at full capacity for a year, this would be 8760 hours of congestion

[9] Average interconnector capacity factor refers to the ratio of total international flow of electricity to the theoretical maximum. The theoretical maximum of 100% would be reached if each interconnector was operating at full capacity for the year

renewables at times of excess production and sharing of flexible generation resources. The high congestion of nearly 3428 hrs/year (out of a possible maximum of 8,760 hrs/year) seen in the Reference scenario means for large parts of the year, there is little headroom that can be exploited in the REmap scenario on interconnectors as they are already highly congested under the Reference scenario. This contrasts with the 2102 hrs/year observed under EU Reference Scenario conditions found in (Collins et al., 2017a) which had uniform EU wide fuel pricing whereas our study here uses differing fuel pricing by Member State. These fuel price differentials result in increased congestion driven by greater short-run marginal cost differentials between Member States which determine the optimal dispatch. The congestion observed is indicative of highly interdependent power system operation which is to be explored in this results section under a variety of headings. This insight is valuable as it implies that, while effective at achieving system-wide increases in renewable energy penetration and substantial decreases in CO_2 emissions, full realisation of REmap options (and even the increased renewable energy penetration beyond today's levels like those achieved in the Reference scenario) can be limited by operational inefficiency induced by interconnector congestion. This interdependence in system operation, in turn, identifies the need for more of a system-wide perspective in the application of the REmap tool for the EU in tandem with the close bilateral Member State level consultation that is currently present. Determining and selecting REmap options in such a way would allow for minimisation of factors such as interconnector congestion and curtailment and maximise the system-wide penetration of renewable energy. This would allow for a more cost-efficient and effective power (and energy) system decarbonisation. In the rest of this section, this chapter discusses the impacts of increased renewable energy penetration on a variety of selected indicators.

6.5.1. Renewable Energy Penetration and Emissions Intensity

Figure 6.4 identifies how renewable and variable renewable energy penetration varies by Member State within the REpower Europe model simulation results of the REmap scenario.

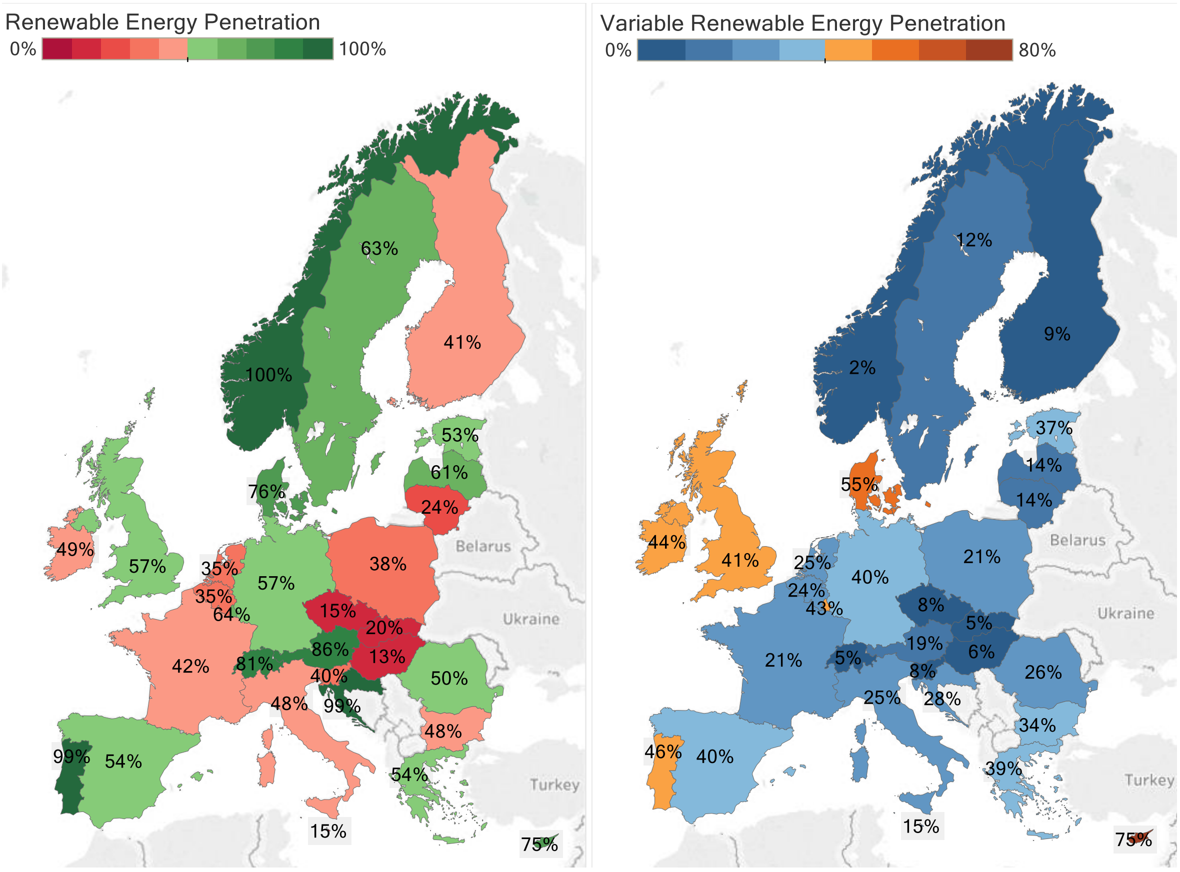

Figure 6.4: Renewable energy and variable renewable energy penetration within the REmap scenario simulation results for electricity generation

Renewable and variable renewable energy penetration differs by Member State due to the varying installed generation capacity by Member State. This itself differs by Member State for a variety of reasons such as resource availability, interconnectivity and penetration of renewables under these simulations. This, in turn, feeds into a varying emissions intensity of generation, shown in Figure 6.5.

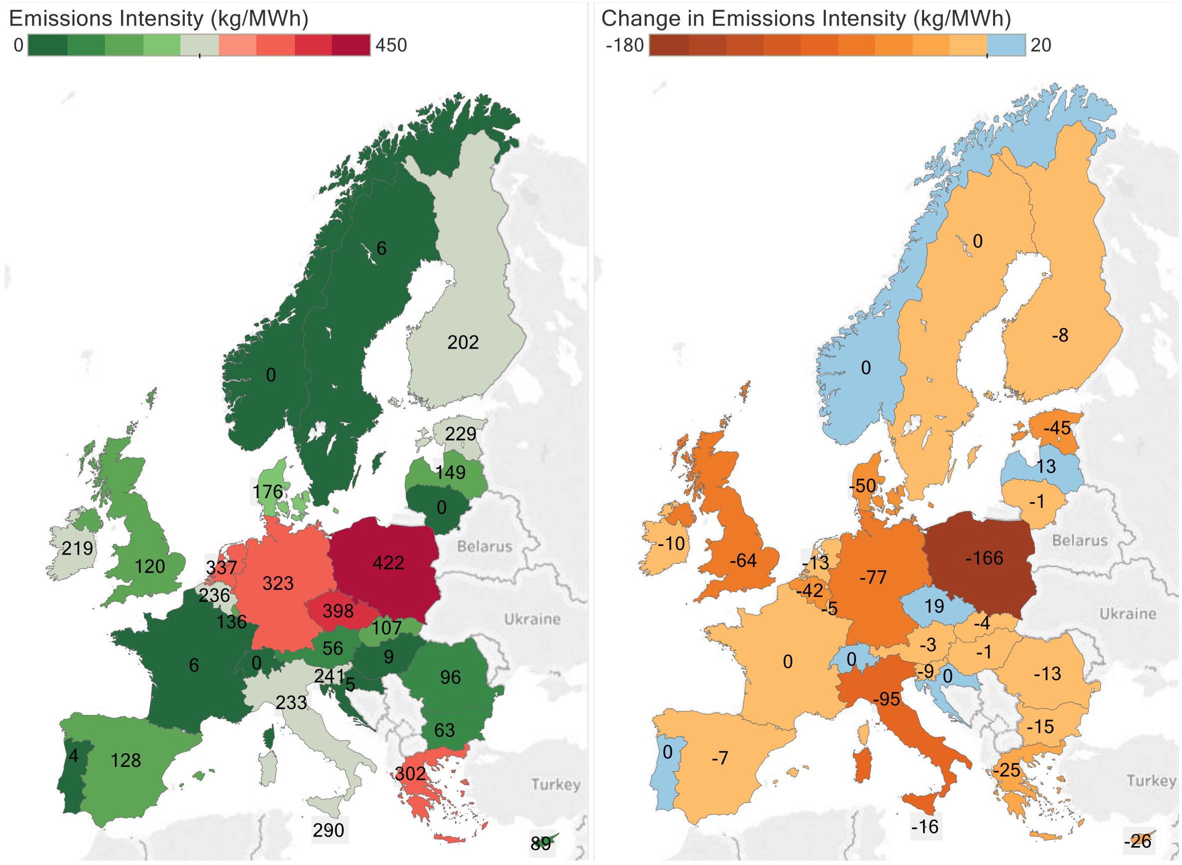

Figure 6.5: Emissions intensity of electricity generation in REmap scenario compared with that achieved in the Reference scenario in 2030

The emissions intensity is reduced across many Member States compared to the Reference scenario, however, this reduction in emissions intensity is not evenly spread across all Member States. This is despite a substantial increase in the penetration of renewable power in all Member States beyond those of the Reference scenario. The two main reasons for this are: 1) Full participation in the REmap programme allowed for deeper power sector decarbonisation pathways in REmap countries than REmap Brief countries, and 2) Increased electrification in the REmap scenario for some REmap Brief countries outpaces or closely matches the increase in renewable energy penetration leading to limited reductions (or even increases) in emissions intensity of electricity. As such, this highlights that increased electrification of transport and heating must be considered in the context of what is generating the electricity. In the case of the Czech Republic and Latvia, this increased electricity demand is largely met by fossil-fuelled generation resulting in higher emissions intensity in these Member States. The power import and export dynamics underpinning these insights and more are discussed further in section 6.5.2.

6.5.2. Electricity Trade and its Impacts on Interconnectors

In 2014, at an EU level, gross trade of electricity accounted for 14% of the electricity consumption (Eurostat, 2015a). However, there was quite a difference between EU Member States in terms of their import and export of electricity. In 2014, Hungary, Lithuania and Luxembourg were net importers for 39%, 79% and 83% of their electricity consumption respectively while the Czech Republic, Bulgaria and Estonia were net exporters for 29%, 34% and 40 % of electricity consumption respectively (Eurostat, 2015a). Figure 6.6 identifies for the REmap scenario of the REpower Europe model which Member States are major exporters and importers of power and compares these results to those of the Reference scenario using the net interchange metric (total exports-total imports). It also shows the ratio of the net interchange to total electricity demand for the REmap scenario for each country. In 2030, the gross trade grows compared to 2014, to around 15% of total electricity demand in the REmap scenario and 16% in the Reference scenario due to the increased number of interconnectors between Member States and the increased penetration of VRE. Increased electricity demand in the REmap scenario means that even though interconnector flow represents a smaller portion of overall demand, the flow of electricity grew by 3% in absolute energy terms compared to the Reference scenario. Even so, high interconnector congestion, even under the Reference scenario, means the difference between REmap and Reference scenarios is rather small in terms of overall electricity cross-border flow and congestion despite a 9.1 percentage point increase in penetration of renewable power.

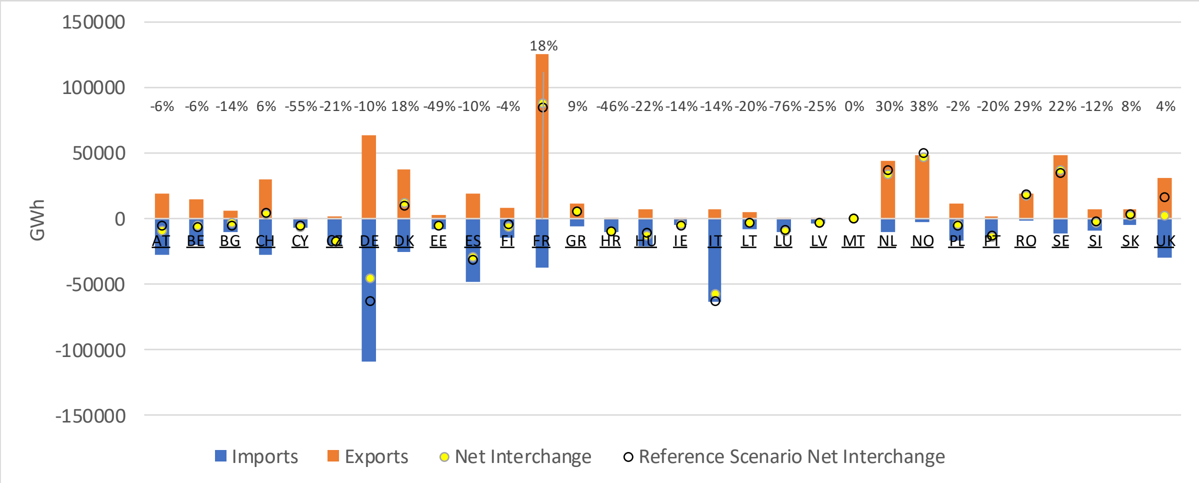

Figure 6.6: Electricity Imports, Exports and Net Interchange (Exports-Imports) for the REmap scenario and Net Interchange for the Reference scenario. The percentage value above each bar indicates the ratio of net interchange to total electricity demand in each country under REmap scenario conditions.

Having both the proportion relative to electricity demand and overall magnitude of this net electrical interchange allows for a rounded and balanced assessment of international power flow in both scenarios. Italy and Germany are the largest net importers of electricity in both scenarios (which for Italy is reduced compared to 2014 situation (-16%) and for Germany is a reversal relative to 2014 levels where it was a net exporter (9%) (Eurostat, 2015a)) and have low emissions intensities in the REmap scenario.

While Italy imports much low carbon power from France (47% of imports) and Switzerland (40% of imports), the same is not fully true of Germany which mainly imports its power from the Netherlands (28% of imports), Denmark (26% of imports) and Austria (21% of imports) under the REmap scenario. The imports from the Netherlands owe primarily to the price natural gas price differential between Germany and the Netherlands but the substantial imports of low carbon power from Denmark and Austria are due to large surplus proportions of low carbon renewable power. While achieving substantial emissions reductions overall, such import dependency directly limits the ability of the Netherlands in achieving similar reductions. Also interesting in this regard is the case of the Baltic states, all of which are major importers, relying heavily on imports from Sweden and Finland.

These examples of import and export dynamics highlight how the flow of low carbon power produced in one Member State is important in achieving a decarbonised power system across a wider region. For example, the congestion on Czech interconnectors under Reference scenario conditions limit the amount of low carbon power that can be imported to meet this demand. Under REmap scenario conditions with greater demand for electricity, these interconnectors become even more congested leading to an increase in carbon intensity of electricity as a result of more domestic coal-fired generation – as shown in Figure 6.5.

The congestion for all interconnectors in this work for both scenarios are presented in Figure 6.7 to further illustrate how congestion on interconnection lines limits the efficient movement of electricity particularly in REmap country lines. However, interconnector congestion must be carefully considered in the context of how binding it is. Congestion, as in Figure 6.7, indicates the number of hours at which a line operates at its maximum capacity but does not indicate how much additional power would be pushed through it if it were of higher capacity. As such, this requires each case of interconnector congestion be assessed individually in the context of how operationally limiting it is regarding cost optimality, VRE integration and system decarbonisation. All interconnectors to Norway are among the most congested in Europe, all bar one of which are congested in excess of 6000 hrs/year, emphasising the utility of its hydro resource to other European countries. Other heavily congested candidates are interconnectors to Sweden which are congested due to their substantial indigenous nuclear and hydro capacity. Interestingly, in the REmap scenario, congestion on the lines from UK to Ireland, Belgium and France reduces compared to the Reference scenario. In the Reference scenario these lines were exporting predominantly from the UK but the REmap scenario saw these lines operate more bi-directionally. The reduced congestion and reduced flow on these lines in the REmap scenario is due to 14% increase in UK electricity demand which saw excess VRE power that was being exported consumed internally. All other lines that were exporting to the UK in the Reference case increased in congestion in the REmap case with an increase in imports to the UK which indicates an increased import dependency.

However, the very slight difference in interconnector congestion generally between REmap and Reference scenarios coupled with the marginal difference in VRE curtailment indicates that the integration of VRE in a pan European context is not too strongly limited by interconnector congestion under REmap scenario conditions.

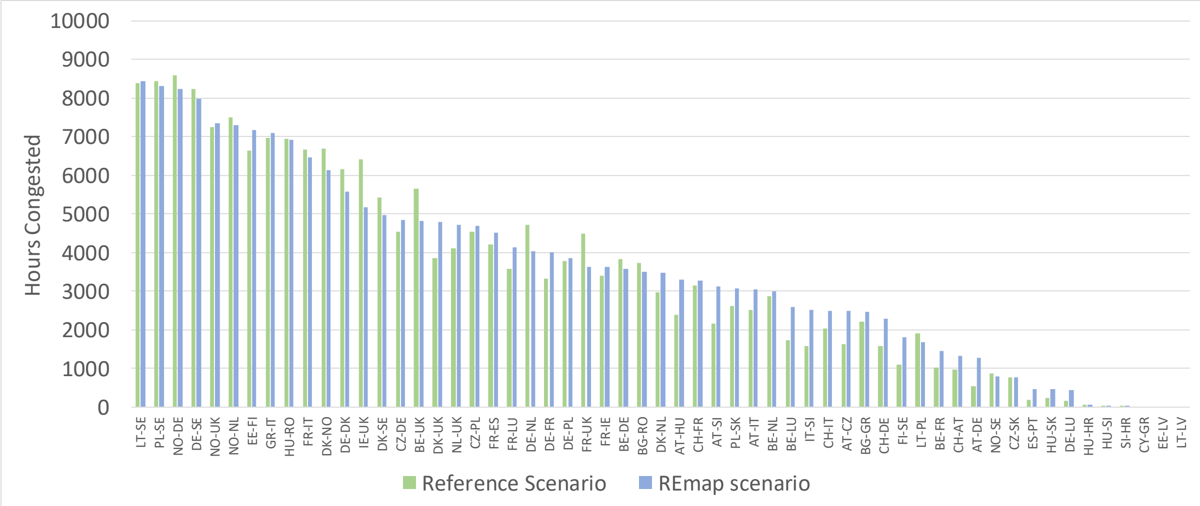

Figure 6.7: Interconnector congestion in the EU in 2030 for both REmap and Reference scenarios

6.5.3. Wholesale Electricity Pricing

The wholesale electricity price is derived based on the average hourly system marginal cost in each Member State over the course of the annual simulation. When wholesale electricity prices are based on marginal costs, some units will not recover all of their fixed operating costs. Uplift is a mechanism that adds to the marginal-cost based electricity price so that no generator makes a loss when both start-up, fuel and emissions costs are considered. Uplift is an ex-post calculation which means that it does not affect the optimal dispatch. Uplift was enabled in this work in the determination of pricing to ensure generators recovered fixed operational costs (Energy Exemplar, 2018a). High penetrations of variable renewable generation across the EU lead to decreases in the wholesale market prices. This is to be expected due to the merit order effect which sees more expensive generators play a reduced role in the generation mix due to predominantly wind and solar generators bidding in at zero due to their zero-marginal-cost.

Figure 6.8 shows the annual average wholesale market pricing for the REmap scenario and the change in price compared to the Reference scenario. Low wholesale pricing raises concerns about the financial viability of conventional and dispatchable generation which are required for security of supply, frequency regulation and other system critical services.

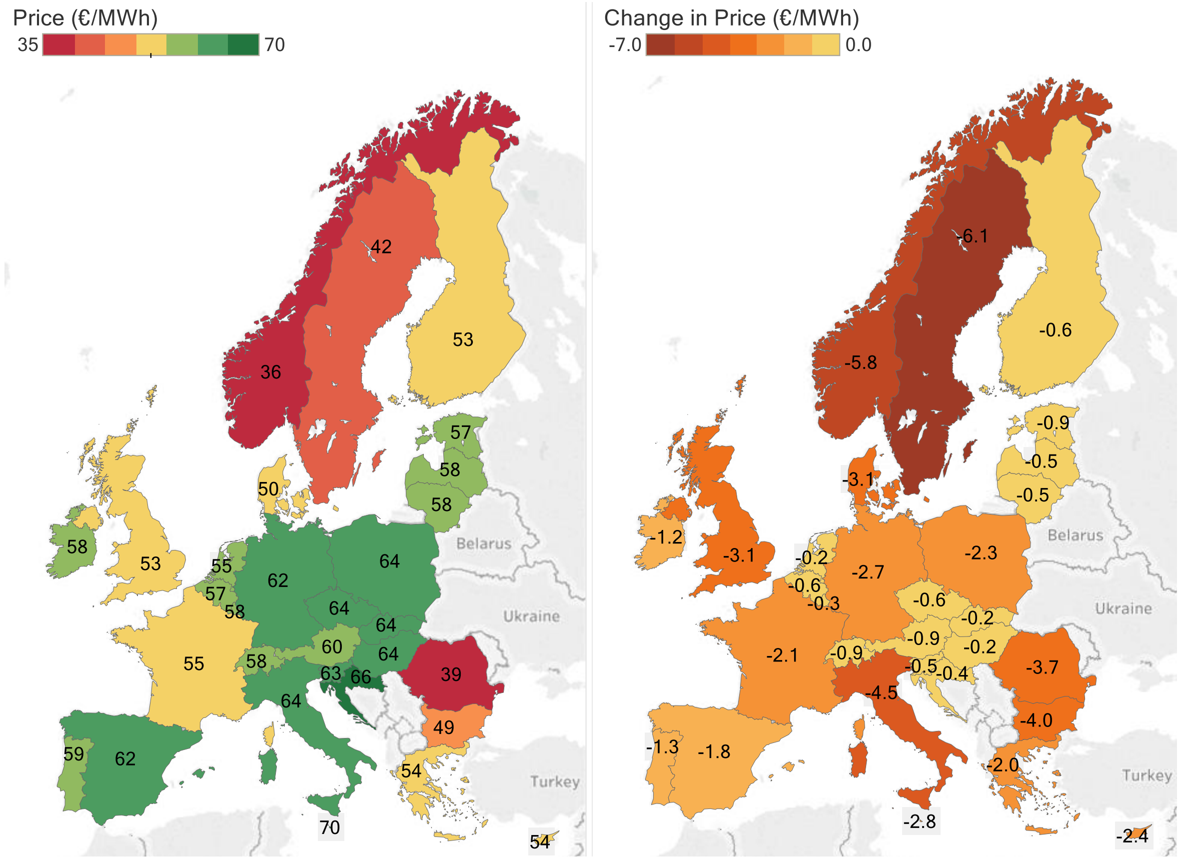

Figure 6.8: Wholesale electricity prices in the EU in 2030 in the REmap scenario and the change in price from Reference scenario in terms of €/MWh

This comparison provides a key finding regarding market pricing in that the price decrease associated with the merit order effect is not evenly distributed across each Member State. This is to say that despite all countries having increased penetrations of variable renewables (that have zero marginal cost and thus typically reduce market pricing with increased penetration), not all countries experience a reduction in wholesale electricity prices. This is largely due to the increase in electricity demand in the REmap scenario limiting the price reducing effects of the increase in the penetration of variable renewables. This results in a more muted impact of the merit order effect within these countries.

To understand the policy implications of these results this situation should be compared with recent events. Since 2008, excess capacity and stagnant demand drove wholesale prices down which resulted in reduced profitability for utilities (Mckinsey & Company, 2014). Wholesale prices dropped from €67/MWh in Germany in 2008 to €28/MWh on average in 2016 (Fraunhofer, 2016). In the REmap scenario, the wholesale price in Germany is €62/MWh where much of its "recovery" from 2016 levels can be attributed to the assumption of a five-fold increase in carbon pricing by 2030 in the REpower Europe model from 2016 levels (European Environmental Agency, 2017). Thus an energy-only market does little to address the “missing money problem” which refers to when markets do not fully reflect the value of investment in resources required to operate a reliable power system. In the case of the EU, much of the present day financial distress is due to overcapacity which means that claims of “missing money” must be carefully considered and could be addressed with improved price formation and measures that address energy and balancing services directly (Hogan, 2017). In a perfectly competitive market, the wholesale price reductions shown in Figure 6.8 should pass on to the retail market but, in the EU, factors such as the market power of incumbents, barriers to entry, administratively regulated prices limit this (European Commission, 2016a). In addition, a substantial portion of retail prices results from regulation which results in taxes and levies which mean that the impact of reduced wholesale pricing on retail pricing is limited. Between 2008 and 2015 EU household and industrial electricity prices increased at an average annual rate of 3.2% and between 0.8% and 3.1%[10] respectively, despite an average wholesale price reduction of approximately 60% (European Commission, 2016a). From a societal perspective, it is important that this disparity in pricing is communicated effectively to end users so that it not lead to a decrease in support for measures that enable the energy transition.

6.5.4. Curtailment of Variable Renewable Energy

Curtailment of variable renewable energy is one metric by which power system flexibility can be measured. It can be viewed as the wind and solar PV generation that was available for production but could not be used. The high penetration of VRE in the REmap scenario indicates that this merits consideration. The ability of this approach to capture generation and interconnector flows at high temporal and technical resolution is critical in capturing the times and frequency at which countries cannot utilise their full renewable generation or indeed export their surplus generation. Figure 6.9 is a graphic displaying the variable renewable curtailment for the EU for the REmap scenario. Total EU curtailment is 0.6% in the Reference scenario and increases marginally to 0.8% in the REmap scenario despite a 9.1 percentage point increase in renewable energy share in the generation mix. Due to the model limitations such as hourly temporal resolution (Deane et al., 2014), perfect market assumptions and limited transmission portrayal, curtailment of VRE should be considered

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[10] Industrial price change varied depending on size band of consumer

a lower bound and would likely be considerably larger in reality. Take Germany and Britain for example which had 5-6% wind curtailment in 2015 with relatively low penetrations of VRE (compared to both the REmap and Reference scenarios we consider) that were of the order of 12-13% (Joos and Staffell, 2018).

Malta at 11% has the highest levels of curtailment due to its isolation as an electricity system, followed by Croatia (5%) and Denmark (4%). Other countries that encounter curtailment are Germany (2%) and Bulgaria (2%). These levels of curtailment should be considered in the context of variable renewable electricity penetration in these Member States: 15% in Malta, 28% in Croatia, 55% in Demark, 40% in Germany and 34% in Bulgaria. Croatia appears to shoulder a disproportionate level of curtailment relative to its VRE penetration, Malta aside, despite its large share of flexible hydro generation in the generation mix. This owes to its limited interconnection which, while substantial in terms of capacity, is solely to Slovenia and Hungary which have rather inflexible generator portfolios with large proportions of nuclear capacity. This limits their ability to import excess renewable power from Croatia as these inflexible units cannot adjust their output in a flexible manner. Our model also does not include the power systems of Serbia and Bosnia Herzegovina which are connected to Croatia in reality and would mitigate its integration of VRE by allowing export of VRE that would otherwise be curtailed. For other Member States, curtailment of VRE is due to high penetrations of VRE and interconnector congestion which limits the ability of the power systems in these countries to absorb greater amounts of variable renewable generation. Key to prudent power system planning in this regard is an understanding of how ambition in terms of deployment of VRE in neighbouring Member States impact each other. An example of this is between Denmark and Germany, both of which have high penetrations of VRE. Whilst having substantial amounts of interconnection to each other and other countries, the inability of Denmark to export sufficient amounts of low carbon power to Germany at times of excess production when Germany itself has large amounts of domestic low carbon power production is a driver of Danish curtailment. There is also the argument that curtailment of such power must be considered in the context of the costs of storage and flexibility measures that would be required to make use of it. Flexibility enablers such as power to heat (Böttger et al., 2014, Ehrlich et al., 2015), power to gas (McDonagh et al., 2018), demand response

(Katz et al., 2016, Nezamoddini and Wang, 2016), battery storage (Sarker et al., 2017) and increased power plant flexibility (Garbrecht et al., 2017) will be important in integrating VRE but should be cost effective when deployed to do so. Curtailment is an inherent undesirable part of a power system with high proportions of VRE but should not be avoided at all costs. If it is prudent to curtail energy then it should be curtailed.

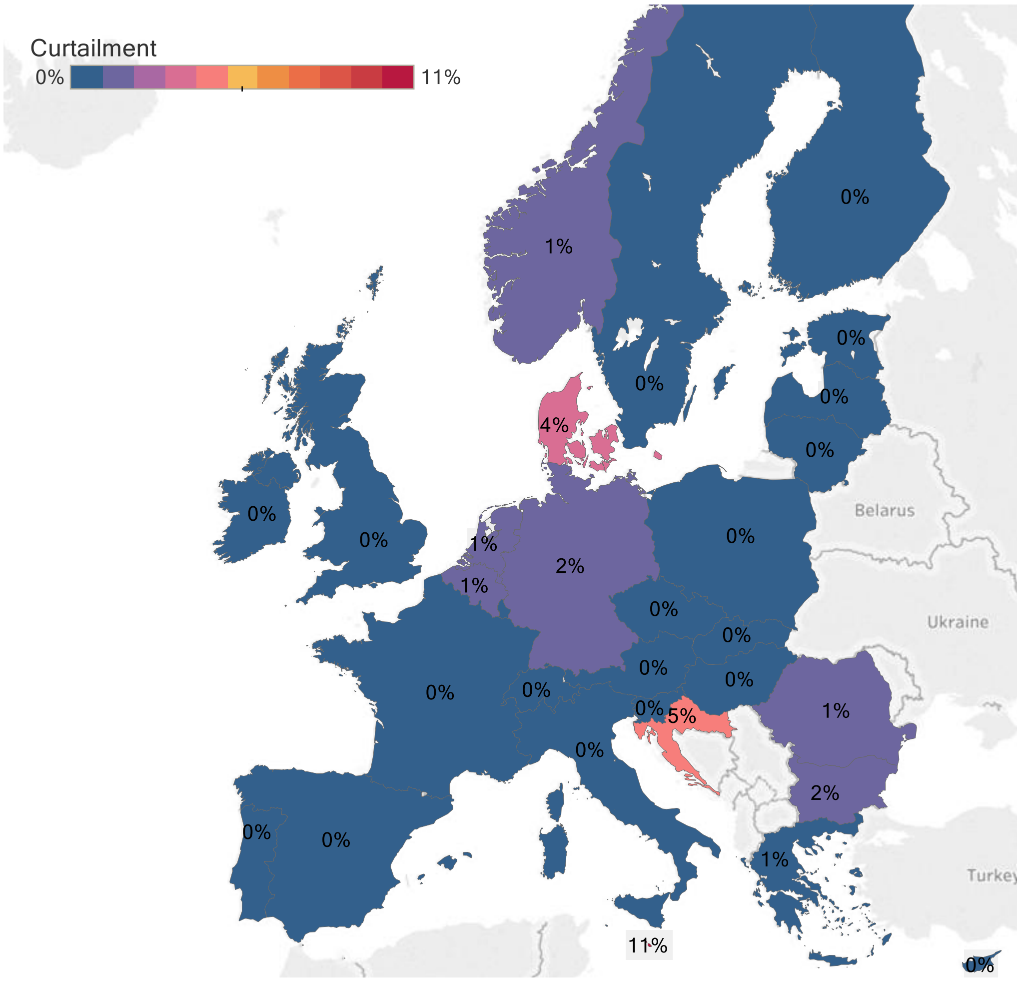

Figure 6.9: Curtailment of wind and solar PV generation in the REmap scenario of the REpower Europe model for Europe

6.5.5. Impact on the Operation of Conventional Generators

Literature suggests that an increase in cycling would be anticipated in the power system realised under the REmap scenario (Schill et al., 2017) which would be accompanied by an associated increase in start-up costs. Heavy cycling could have onerous effects on the components of these units and potentially lead to increased outages and significant costs (Troy et al., 2010). Increased variability of generation on the supply side inevitably increases the importance of flexibility options on the system required to mitigate this variability. Although the total generation of fossil-fuelled generation is significantly reduced, such generators are still significantly used to bridge the increased variability in electricity generation from VRE. Curiously, the difference between the REmap scenario and the Reference scenario is very marginal in terms of starts per unit. As shown in Table 6.2, most generators experience increased cycling of units (albeit muted) to offer the requisite generation which cannot be met by variable renewable generation when comparing the REmap scenario to the Reference scenario. This demonstrates the maintained reliance on flexibility options with significant ramping capability.

Table 6.2: Number of starts by generator per year per unit

	REmap	Reference
Natural Gas CCGT	66	66
Natural Gas OCGT	2	2
Biomass Waste	80	67
Oil	22	25
Coal Fired	43	40
Derived gas	58	55
Nuclear	31	29

The increase in electricity demand (of 6.2%) in the REmap scenario means that this increase in cycling was more muted than would be the case with consistent demand between both REmap and Reference scenarios or greater penetrations of VRE in the REmap scenario. Such a scenario was also simulated in this work, with demand held at Reference scenario levels but simulated with the installed capacity mix of the REmap scenario. This showed that the mismatches between VRE supply and demand grew larger and flexibility required of the system was greater leading to much more notable increase in the cycling requirement of generators than in Table 6.2. These conditions also led to the installed capacity of conventional generators to be oversized relative to demand which indicates that starts per unit would be even higher if the conventional generation capacity were adequately sized. Capacity factors per unit would also be higher under these conditions so may sufficiently compensate financially for these higher cycling costs, however, such a financial assessment is beyond the scope of this work.

It is prudent, however, to consider how often such generators operate over the course of a year by Member State as it provides direct insight into their revenue stream under energy only market conditions. Figure 6.10 identifies the capacity factor by Member State for natural gas CCGT generators in the REmap scenario (left) and the annual number of starts per CCGT unit per year (right).

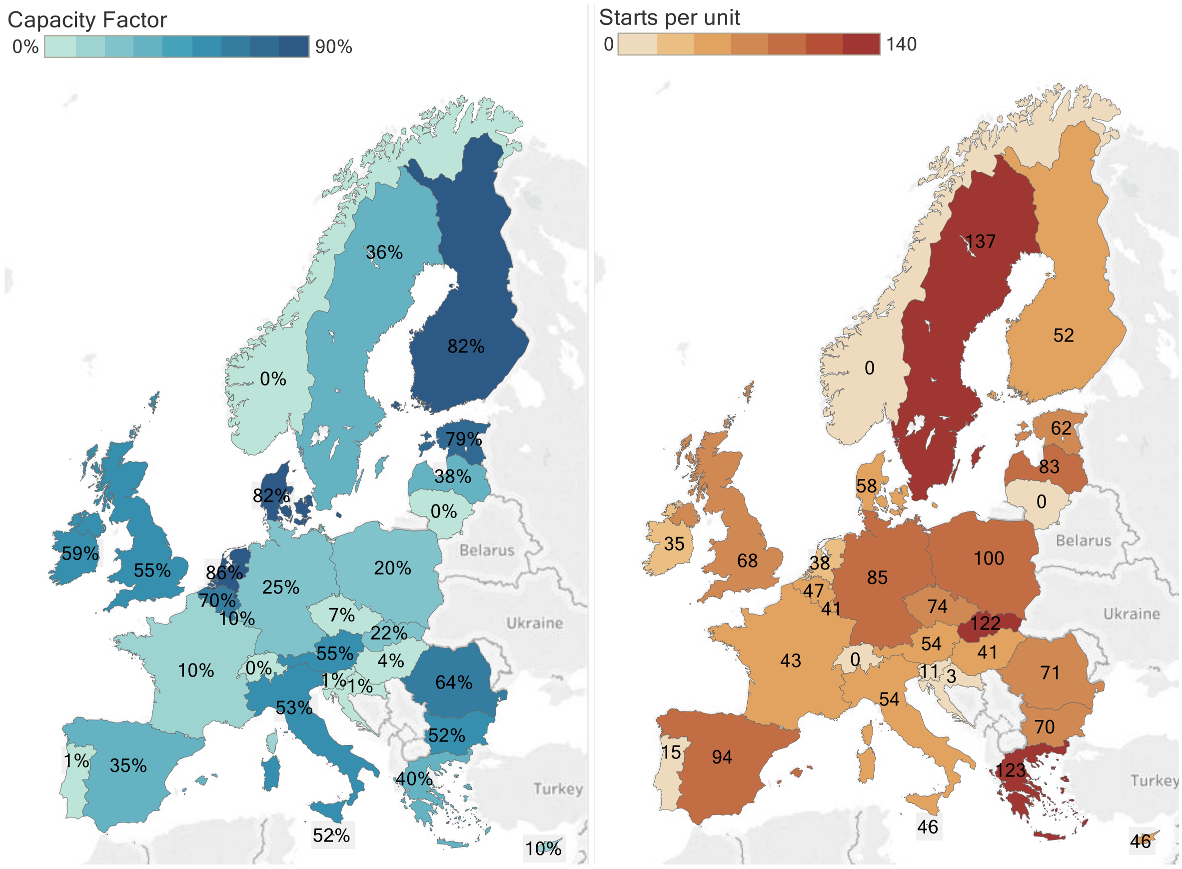

Figure 6.10: Capacity factor and number of starts for combined cycle gas turbines in the EU in 2030 under the REmap scenario

The analysis of the generator's ability to recover all costs from the markets is beyond the scope of this study; however, the low capacity factors resulting from the simulation for some Member States, indicates that their economic viability could be potentially at risk. Under the REmap scenario, the average natural gas plant in the EU-28 would operate at an average capacity factor of 39%; however there are large differences between Member States as shown in Figure 6.10. Most Member States in the REmap scenario are in light blue on the left and in darker shades of brown on the right, indicating very low operation (and an implicitly low revenue stream under these market conditions) and high start-up costs. Stand out candidates are Hungary, Czech Republic, Portugal and Slovenia which all have capacity factors well below 10% and an average of 35 starts per unit.

Under the REmap scenario, coal generators operate at an average capacity factor of 52% across the EU. However, there are significant differences across Member States. While in some Member States they are expected to operate at relatively high capacity factors e.g.

FR, IT, NL, GR, PL, DE, FI, SK, SI, in other Member States e.g. AT, BE, BG, EE, HR, HU, RO, the remaining coal capacity would be hardly in operation, with capacity factors below 10% in some cases.

Combined with the reduced market pricing shown in Figure 6.8 this indicates that such dispatchable generators may struggle to achieve sufficient financial remuneration under energy only market conditions.

6.6. Discussion

The insights derived from this work identify numerous benefits and challenges associated with the power sector transformation projected in the European REmap analysis. This section starts by discussing the benefits of the methodology applied in this study that combines two separate approaches: The REmap approach and use of a soft-linked dispatch model (the REpower Europe model). Subsequently, it compares the two models to provide more insights to the reader about the right balance of model complexity and ease of use that is needed to draw conclusions for energy policy design.

6.6.1. Benefits of Soft-Linking the European REmap Analysis to the REpower Europe Model

The objective of this chapter is to provide policy insights derived from the combination of IRENA's REmap analysis with the REpower Europe model, which performs a dispatch simulation of the European power system for two scenarios for the year 2030. Results must be considered in the context of the methodology that was applied to derive them so as to fully appreciate the value of the outputs. The application of this soft-linked methodology enabled insights to be gained into how such a renewable power system, as suggested by the REmap analysis, would operate by modelling its operation at high technical and temporal resolution. Doing so enabled the capture of challenges and implications on EU power system operation that will accompany this transition, thus complementing the REmap analysis.

The REmap analysis (in the REmap scenario particularly) is shown to achieve substantial decarbonisation of the power sector by 2030 with low levels of VRE curtailment. This analysis showed however that this decarbonisation was not evenly spread across all

Member States and that increased electrification, even if accompanied with increased penetration of renewables, can lead to increased emissions intensity of electricity accompanied by modest reductions in wholesale electricity prices. These impacts though were largely confined to the REmap Brief countries which from a policy perspective shows how a detailed assessment is required to determine deeper decarbonisation pathways for these power systems.

The relatively high amount of curtailment in Croatia (5%) and Denmark (4%) under REmap scenario conditions also shows how power sector planning must be cognisant of the power system planning in the broader region which may inhibit their integration of renewables. Exports at times of excess VRE production can be limited due to interconnector congestion, inflexible generation mixes or saturation of VRE in these neighbouring countries which leads to greater amounts of VRE curtailment. Increasing power sector flexibility using flexibility measures such as increased interconnection, demand response, power to heat, power to gas, pumped hydro electrical storages and battery storages can help system operator mitigate the integration challenges of VRE.

A key element in the operation of the power sector in both REmap and Reference scenarios was highly congested interconnection that limited the efficient flow of electricity which in turn induced curtailment of VRE power in some Member States. Such interdependency highlights the required system-wide focus when developing renewable energy roadmaps for countries. This points to challenges over the flexibility of the power systems within these Member States and suggests that further interconnection options should be explored beyond what is planned by ENTSO-E under the conditions projected under REmap and Reference scenarios in this work. Such exploration of further interconnection options should be performed with a sensitivity analysis regarding fuel pricing as well as carbon pricing so as to provide a robust assessment of interconnection candidates. Such analysis should also be conducted whilst considering the potential benefits of other flexibility measures to ensure cost effective integration of VRE.

Another insight gained is that in an environment with greater penetrations of VRE, conventional dispatchable generators may struggle financially in some Member States due to lower capacity factors, lower market pricing and higher start costs. Within today's European power sector, current market prices are insufficient to cover the fixed costs of all plants operating on the system (Deane et al., 2017) but much of this is due to the current levels of overcapacity in most European markets (del Río and Janeiro, 2016). This points to the potential need for a combination of measures such as coordinated phasing out of certain generation capacities coupled with alternative structures and policies (such as capacity markets) for these technologies to remain a viable source of flexibility and balancing.

6.6.2. Comparison of the REmap to Power System Dispatch and Energy System Modelling

The REmap analysis is a simple spreadsheet-based approach which spans the entire energy system of the countries to which it is applied. The strength of the REmap approach is that it is a transparent and straightforward way to engage with national experts and other stakeholders for the development of decarbonisation pathways. It also provides powerful insights into future needs of the power system under wider energy system decarbonisation and makes useful datasets (such as cost data (IRENA, 2017a)) openly accessible for the wider energy modelling community.

However, if viewed form a modelling perspective the approach does have a number of shortcomings. It does not consider the optimality of the energy system projected (a strength of energy system optimisation modelling) and doesn't capture the detailed operation of various sectors of the energy system (a strength of power system dispatch modelling for the power sector) and their interactions (a strength of energy system optimisation modelling) since the process of choosing REmap options does not consider them. These are left to the discretion of the analyst and whether there are other models available to enable a more detailed understanding be gained of the choices.

The strengths of power system dispatch and energy system optimisation modelling are offset by their reduced amenability to stakeholder engagement. This is due in large part to the complexity and expertise required to develop, maintain and understand the results of these models to derive meaningful policy. Presenting policy and decision makers with a selection of renewable energy options across the entire energy system in a simple fashion allows for easy interpretation and discussion of energy policy which in turn facilitates development and implementation. This is, of course, should be carefully executed given the inherent aforementioned weaknesses of the REmap approach.

Core questions that follow on from this work are (a) are REmap spreadsheets alone enough or are more complex tools really needed, and (b) what is the right balance of model complexity and operational ease. This chapter provides many operational insights but, by definition, an operations planning model is not best suited to assess optimal investments. There is no "silver bullet" approach to planning a decarbonised European power sector but this chapter shows how one approach can be leveraged to gain a deeper understanding of the findings made in the application of another. As such this shows that a combination of approaches is best applied to allow for a broad-based assessment of energy policy. This stands not just for the electricity sector but for all energy end uses such as those in the residential and transport sectors where multi-model approaches are shown to facilitate a better understanding of the technology pathways needed to meet decarbonisation targets and thus lead to more informed development of policy roadmaps (Mulholland et al., 2017, Deane et al., 2015b).

The iterative bi-directional process in which modelling insights were interchanged between REmap and the REpower Europe model has helped to identify the operational difficulties where the choices for REmap options were overly optimistic. An example of this iterative approach was the French power system generation mix which was revised as it was found that the original REmap findings would lead to operational problems and unserved energy in the French power system. This occurred because the excessive replacement of Nuclear generation with variable renewable wind and solar power which led to an inadequate generation mix. Coupling with REpower Europe model allowed this weakness to be identified and addressed, which enriched REmap without compromising its amenability to engagement with stakeholders.

6.7. Conclusions

In conclusion, the analysis performed in this chapter provides insights into the operational realisation of the European power system with higher shares of renewable energy technologies based on the power generation capacity mix developed under the REmap policy tool. The REmap analysis at the time of writing included the complete assessment of the power generation mix for 10 Member States that covered 72% of the EU total power generation and it was supplemented by a process (Section 6.4.2.2) that enabled the assessment of the capacity mix for the remaining 18 countries starting with the baseline capacity mix according to the EU Reference Scenario. At a system level, the REmap scenario capacity mix is shown to be an effective high-level assessment of the renewable energy technology options for the power sector in 2030. This is evidenced by achieving a 50.2% renewable energy share in electricity generation (of which 29.0% is VRE) in 2030 (compared with a 41.1% renewable energy share in electricity generation (of which 21.3% is VRE) in the Reference scenario) with a low level of wind and solar PV curtailment (0.8%).

The value provided by this work is that it allows the operation of a highly renewable European power sector to be assessed at high technical and temporal resolution. Using a pan European power system dispatch model makes it possible to analyse, in detail, the relationships between neighbouring countries and their generation mixes under greater penetrations of renewable energy. This process captures the impacts of hourly power flows between Member States which strongly influences results and allows balanced assessment of the impact of renewable power, especially variable renewable power, on system operation in a broader context. Silo-based focus can lead to unrealistic and suboptimal assessment of decarbonisation potential of the overall European power sector, as shown in (Deane et al., 2015d). The insights gained from this detailed power system modelling can be directly used to inform policy development by providing high-level REmap options cognisant of this interdependency. Policy development for the power sector must be cognisant of the integrated nature of European power markets and doing so will lead to more effective and cost-efficient decarbonisation by accounting for challenges described in this work.

Supplementing the REmap approach with more detailed sectoral modelling provides many insights and adds a certain robustness to the findings of REmap for the power sector. Determining energy policy pathways for the European energy system for all sectors could be best achieved with similar sectoral modelling using a suite of models and approaches. The unified use of such approaches, however, is quite complex and strays somewhat from the core strength of the REmap approach which resides in its ability to engage stakeholders in a transparent and straightforward manner. A general weakness of approaches that soft-link to dispatch models is that they often are soft-linked to complex analyses (such as the application of energy system models) which are not as amenable to stakeholder engagement as REmap. Another strength of REmap in this regard is that it also relies on detailed data regarding localised renewables potentials and costs which are often not available in the application of dispatch model soft-linking analyses. Future developments and applications of the REmap approach must make these trade-offs between complexity and its ease of use and application with this in mind.

A key avenue for future work would be to enhance the representation in the model to be of greater nodal representation, this is particularly true for large countries such as Germany and the United Kingdom. This would allow for more detailed assessment of which regions are most acutely affected by increased penetrations of renewables. Representing large countries as one single node makes it challenging to provide more detailed advice for policy-makers in these countries. Another interesting avenue for future work would be to expand this analysis to run based on long-term wind and solar datasets so as to determine the operational sensitivity of these results to fluctuations in long-term weather patterns. Future work is also proposed to analyse the impact of demand response and a variety of EV charging patterns system operation. In a broader sense, the cost optimality of the energy system projected using the REmap approach could be assessed and improved by using insights gained from energy systems optimisation models, such as TIMES (Loulou et al., 2005), in direct combination with the REmap analysis which would allow for the assessment of optimality of investment.

Chapter 7: Conclusions

The aim of this thesis is to improve the knowledge base underpinning European energy policy decisions by helping improve power sector representation in long-term energy system planning. In achieving this aim, this thesis addressed the key research questions outlined in section 1.3, which to facilitate discussion are reiterated and answered in brief below based on the findings of this thesis:

Question 1: What is the present state-of-the-art in accounting for short-term variability of power sector operation in long-term energy planning?

Answer 1: The present state-of-the-art was established in chapter 2 and determined that the best choice of methodology differs depending on the bespoke needs of the modeller and nuances of the study in question.

Question 2: What insights are gained by modelling analyses underpinning European energy policy at high technical and temporal resolution for the power sector?

Answer 2: Chapters 3 and 4 highlight the current weaknesses within, and add value to, European studies that are currently informing policy developments. Chapter 3 provides insights into interconnector congestion in particular associated with EU renewable electricity ambitions that previous analyses did not reveal. Chapter 4 provides insights into renewable electricity flows between Member States, highlighting possible cross-subsidisation.

Question 3: What is the influence of the inherent weather dependency of generation on power system operation?

Answer 3: Weather dependency is shown in Chapter 5 to strongly influence system operation under the decarbonisation scenarios considered, and increases with decarbonisation ambition. Ignoring this power system weather dependency in energy system planning risks it being ineffective and inappropriate.

Question 4: How can methodological improvements be used to enable improved energy policy formulation?

Answer 4: Methodological improvements allow for better representation of the integration challenges of renewables and of the challenges of achieving a low carbon future. Chapter 6 is the outcome of collaboration with the IRENA on this topic – adding value to the REmap analysis with a detailed exploration of the robustness of the renewable electricity results.

The answers to these questions are further detailed in this concluding chapter and are divided into three sets. The first set are derived from the methodological gains made in European energy system planning, the second set are derived from the operational insights gained that shed light on the future operation of the European power system and the final set are the key conclusions from this thesis that can be used to inform European energy policy development.

7.1. Conclusions on Methodology

As determined in chapter 2, the best methodology applied to improve the representation of short-term power sector variability in long-term energy system modelling must be carefully considered in the context of the advantages and disadvantages of each methodology and the nuances of the study to which they are applied. Quantitative comparison of the results of studies performed in chapters 3, 4, 5 and 6 is possible because of the application of a consistent methodology to all datasets considered. The methodological consistency in attaining the insights gained allows for balanced comparison of the operational challenges encountered under varying degrees of decarbonisation ambition.

Different studies have different limitations and model coupling allows the limitations of individual studies to be overcome with detailed operational modelling. The increasingly variable and heavily interconnected nature of European power system operation makes such interplay between power and energy system planning an essential consideration for energy policy. The model coupling process allowed for operational insights to be gained throughout this thesis such as those into the evolution of wholesale electricity pricing, interconnector congestion, capacity factors of fossil fuel generation, curtailment of variable renewable generation and provision of synchronous inertia, among others, which are mostly either not captured at all or poorly represented in the studies considered. Model coupling enriches our understanding of energy system decarbonisation scenarios by showing the outcomes of their operational realisation under unit commitment and dispatch constraints.

Methodologically, the PRIMES, REmap and the ENTSOE-E scenarios that were soft-linked to a dispatch model in chapters 3, 4, 5 and 6 were themselves developed using different approaches and/or models with different objectives. PRIMES was developed to determine optimal technological pathways for European energy system development, REmap was developed to facilitate better energy policy engagement with stakeholders while the ENTSO-E scenarios were developed with a view to planning the development of the European transmission system. The differing focus of these studies leads to them having differing input assumptions and accommodating such a wide range of perspectives is important, methodologically speaking, because of the wide range of concerns that are implicitly accommodated in these underlying assumptions and their corresponding impact on results. Far from advocating a "one model fits all" approach, this thesis has established through soft-linking with these studies that each has an important role to play and a broad scope is essential in informing the coherent development of policy.

The differing focus of these scenarios led to differing grades of representation of power and energy systems. For PRIMES and REmap scenarios considered, the soft-linking process allowed for better representation of power sector operation that was not possible in their original respective frameworks by facilitating better power sector representation both technically and temporally. This thesis adds weight to the insights gained in these studies by determining how the systems would work in reality using highly resolved modelling of a continental power system. A conclusion derived from this is that it is important to carefully consider the representation used in modelling when evaluating policy derived using these frameworks and that such concerns can and have been addressed in this thesis for the power sector by using detailed sectoral modelling.

The increasing reliance of the European power system on wind and solar generation, in particular, make it crucial to understand how long-term weather patterns impact their ability to contribute to the operation of a reliable power system and how this changes with decarbonisation ambition. The impacts on some dimensions of system operation and investment are more important than others. Wholesale pricing, generation costs VRE curtailment, CO_2 emissions and generator capacity factors are all strongly impacted by inter-annual weather variability and have direct knock-on effects for power system planners that make it an essential consideration. This thesis has shown how energy and power system modelling and subsequent planning derived from such works must account for the long-term variability of the resources underpinning its decarbonisation. Otherwise, they are at risk of being ineffective and inappropriate for energy planning by being ignorant of the weather dependency of the energy system.

A variety of different profiles characterising the variability of wind and solar PV generation have been used throughout this thesis. Encouragingly, over the time in which this research was undertaken there was a notable increase in the availability of publicly available validated renewables datasets that can be freely used for modelling studies. At the beginning of this thesis, in chapter 3, there was no publicly available dataset of validated wind generation profiles available at a European level which meant such a profiles had to be specifically created. In later chapters this was not an issue with public sources being used for both wind and solar generation throughout.[1] The benefits of using publicly available validated profiles are substantial and their use and development should be further encouraged because they give modellers an "off the shelf" trustworthy dataset they can use and allow the wider community to trust the results of such studies.

An important benefit of soft-linked model coupling is an ability to use its insights to refine results of the long-term energy planning studies. However, this requires a bi-directional interchange of results between the dispatch model and the study to which it is soft-linked to facilitate refinement. In this thesis, the soft-linking has mostly been uni-directional (in chapters 3, 4 and 5) which doesn't facilitate refinement of results. The bi-directional soft-linking undertaken in chapter 6 with the REmap tool was constructive in this regard because it allowed this refinement of the power sector results to occur. Bi-directional soft-linking should be encouraged to facilitate improved energy system planning for the power sector and all energy end-use sectors.

[1] For chapter 5 the publically available dataset used was modified to account for changing dispersion of wind farms under more aggressive decarbonisation

7.2. Conclusions on Operational Insights

Increased electrification, while reducing overall emissions, is shown in certain cases (in chapters 5 and 6) to lead to an increased CO_2 emissions intensity of electricity generation despite a substantial increase in the installed capacity of renewables. However, this increased electrification could aid renewable integration challenges and reduce costs by offering demand-side flexibility, as shown in chapter 3. Thus, to improve the optimality of outcome, any increase in electrification must be carefully considered in overall energy system planning in the context of what trade-offs are being made in meeting this additional electricity demand.

Integration challenges for renewable energy can be generalized on a continental scale but are in reality quite nuanced at a country level which are strongly dependent on the levels of interconnection, the composition of generation mix and flexibility of generation mix in the countries to which they are interconnected. This thesis has shown that it is essential that national power system development be cognisant of broader regional power system planning so as to approach cost optimality. Incoherent planning has been shown to lead to a more challenging, more costly and less effective route to a low carbon future, as also identified in previous works (Deane et al., 2015d).

Curtailment of VRE has been shown in this thesis to be highly reliant on power system flexibility within each country and within their respective neighbouring countries. Integration of high shares of VRE can be limited by curtailment which has been shown to occur due to lack of an export market at times of excess production and exacerbated by localised operational constraints such as generator minimum up and down times and system synchronous inertia constraints. The examples provided throughout this thesis, such as for Denmark (in chapters 5 and 6) which despite high levels of interconnection had significant curtailment and Ireland in chapter 3 which had significant curtailment due to it being constrained to maintain minimum synchronous inertia levels, identify that many elements must be considered for minimising curtailment and determining the implicit optimal distribution of VRE installations at a pan-European level.

Increased interconnector flow corresponds to greater interdependency between countries under higher decarbonisation ambition and allows an increasingly variable electricity supply to meet demand across broad geographic areas which smoothens supply-demand mismatches. Interconnector congestion has been shown to limit the export of excess variable renewable generation and sharing of flexibility resources between countries and leads to increased power generation costs, CO_2 emissions and curtailment of VRE, and should thus be minimised.

Increased penetrations of VRE have been shown to depress market prices due to the merit order effect throughout this thesis. Intuitively, the capacity factors of conventional fossil-fuelled generation have been shown to reduce in magnitude under decarbonisation though with an increased inter-annual variability. Given that these generators are the source of all power sector CO_2 emissions in the scenarios considered, it follows that CO_2 emissions have followed suit. All these factors in market operation combine to present a new reality for system operators which requires careful oversight to ensure a transition to a reliable clean power system.

7.3. Conclusions for European Energy Policy Development

The key policy conclusions drawn in this thesis are a conflation of both the methodological and operational insights gained into long-term energy system planning.

Increased model complexity facilitated by either soft-linking or direct model/methodology modification allows for improved representation of the energy system and challenges associated with the energy transition. This thesis demonstrated this for the power sector but it is true for all end-use sectors. A weakness arising from this increased complexity, however, is more cumbersome model management and reduced amenability to decision makers and stakeholders. A dispatch model on its own is not best suited to determining optimal investments because such models would become quickly become computationally intractable were they to also optimise capacity expansion. They are also not best suited enabling stakeholder engagement because by their nature they require expertise to carefully interpret the nuances of their outputs with respect to all modelling and data assumptions. However, this thesis has shown when coupled with other studies it can add robustness to works where these are the focus. Thus, leveraging a suite of models to gain insights into the results each other is the best course for gaining an improved understanding of technology pathways to thus facilitate more informed development of energy policy.

This thesis has demonstrated the influence of neighbouring countries power systems on each other's renewable power integration challenges and how incoherent power system planning can maximise these challenges and lead to suboptimal development of policy. Energy policy development must be internationally coherent in order to maximise the integration potential of renewables and lead to a minimisation of CO_2 emissions and costs.

Methodologically, it is important that modellers base studies on data that is representative of long-term conditions so that the energy and power systems planned are operationally robust to the long-term variability of resources underpinning its decarbonisation. Measurement of progress towards decarbonisation and renewable energy ambition mandated by policy also must fully incorporate this so as to ensure fair assessment of progress.

Arising from improved and coherent representation of the interactions between power and energy systems is improved capture of specific decarbonisation challenges for the power sector. This thesis has a number of policy-relevant conclusions in this regard which allows more effective policy to be devised to mitigate these specific challenges:

- Curtailment is an inherent part of a highly renewable power system. Policy devised to facilitate additional flexibility measures such as increased interconnection and storage should be carefully considered in the context of what they would cost and not devised to with a view to eliminating curtailment at all costs.
- Any exploration of further interconnection options should be as part of a balanced multi-variate analysis performed so as to provide a robust assessment of interconnection candidates. Such analysis should consider the sensitivity of candidates to fuel and carbon pricing and the potential benefits of other flexibility measures to ensure cost-effective integration of VRE.
- Increased interconnector flow accentuates uncoordinated support mechanisms, price distortions and cost inequality in the European electricity sector. This leads to cost inequality as consumers are left to remunerate the renewable electricity producer out of market while the energy is consumed out of state. Support

mechanisms may be best approached from a supranational perspective to create a level playing field, free of price distortion created by differing support structures.

- Wholesale electricity price reduction is a result of increased penetrations of zero marginal cost variable renewables on a power system and under energy-only market conditions can fail to appropriately value flexibility and balancing provision. Coupled with conventional generator's lower capacity factors, increased operational cycling and higher start costs, improved price formation and an implementation of measures may be required to address flexibility and balancing services directly.

Current European energy policy development, including the recent determination of a 32% renewable energy target, still lacks sufficiently high-resolution modelling underpinning it. This can cause sub-optimal policy development that lead to sectoral operational challenges, as found in chapter 3. Key to the effective overall energy system decarbonisation is the development of rounded energy policy fully cognisant of the effective role of the power sector within energy system decarbonisation. Long-term energy system planning models and other policy and planning tools are useful for determining this role and are strengthened when combined with more detailed sectoral modelling for all end-use sectors. Open models and open data are important for facilitating trust in such works underpinning energy policy development and an open co-operative nature in the development of such studies is equally so. Policy development (and studies underpinning them) that is openly verifiable, interoperable and cognisant of a broad range of considerations are important in ensuring coherent development of policy. By using a consistent methodological framework throughout and making models and data openly available, this thesis has brought a consistency to a variety of studies that are actively being used to inform European power and energy system policy. This allows for careful consideration of policy that can be verified by various stakeholders which thus facilitates scrutiny of data and modelling underpinning costly and climatically critical policy decisions.

7.4. Future Work

This thesis does not claim to be a "silver bullet" solution to the challenge of achieving energy system decarbonisation and much remains to be studied and more questions must be asked in order to plan a robust decarbonisation of European power and energy systems.

A key avenue for future work generally would be to further analyse all scenarios analysed in this thesis by increased application of a bi-directional soft-linking approach with a wide range of sectoral models. This would implicitly lead to a more inter-institutional collaborative approach in the development and refinement of European energy policy which would improve the optimality of results by facilitating cross-disciplinary refinement.

More specifically for the power sector, the work of this thesis could be furthered by improved power sector representation in relation to the following:

- Greater nodal disaggregation would permit better representation of the VRE integration challenges by allowing identification of localised pinch points for VRE curtailment and interconnector congestion. This is strongly reliant on data availability but would make it possible to represent transmission and distribution constraints below country level that will be crucial in representing renewable energy integration challenges in particular those associated with distributed generation.
- Improved representation of technical constraints would allow for better representation of the technical operational challenges that may be limiting factors in integrating high shares of renewable energy onto the power system. This coupled with greater nodal disaggregation would allow for a more targeted policy to be prescribed within the context of the European power system.
- Better representation of operationally limiting constraints of hydroelectric power would make the modelling performed more representative of the challenges they pose for renewable energy integration. All the work within this thesis assumed a very high level hydrological and operational flexibility that, while representative of historic monthly aggregated power output, by neglecting the operational complexity of such systems (such as that which accompanies the simulation of

cascaded and multi-year storage systems) will likely have overestimated this operational flexibility.

- Improved electricity demand profiles that better account for the changes in demand that will be caused by increased electrification of transport and heating sectors would make modelling more representative of the operational challenges they pose. A more disaggregated load would also allow for demand response measures to be studied in a more targeted fashion which would result in better understanding of these energy policy measures.
- Representation of the long-term weather induced variability of European hydro generation and electricity demand. This thesis studied the impact of long-term wind and solar variability on European power system operation in chapter 5 but due data limitations and the scope of the work, hydro and demand variability in this respect were not captured. Capturing this additional long-term variability in modelling would be challenging but very enriching in terms of understanding it would provide of how they evolve under decarbonisation that would in turn allow for better policy to be devised.

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Appendices

Appendix A

This appendix serves to provide a numerical breakdown of colour coded figures developed for chapter 3.

Table A.1: Electricity generation by mode and by member state in 2013 PRIMES REF results for the year 2030

Country	Biomass Waste (GWh)	Hydro (GWh)	Natural Gas (GWh)	Nuclear (GWh)	Oil (GWh)	Other (GWh)	Solar (GWh)	Solids Fired (GWh)	Wind (GWh)
AT	6805	45467	6809	0	329	0	1961	724	13359
BE	8779	534	39653	0	987	0	5405	1882	17582
BG	253	4631	8495	15310	588	0	2375	24069	2684
CY	152	0	4851	0	55	0	1254	0	850
CZ	4091	3446	5180	45074	117	0	2223	19497	632
DK	4682	23	8415	0	583	0	784	513	19521
EE	491	118	1576	0	0	0	0	6861	2613
FI	7124	14157	5224	59443	348	0	58	6830	6706
FR	21100	67806	23169	369072	633	1790	22385	0	125218
DE	40511	25917	133915	0	2453	0	55897	159097	163062
EL	573	9012	22251	0	2614	0	5729	7076	9742
HR	372	7853	3727	0	318	0	272	791	1451
HU	3335	258	3617	32289	267	0	798	1607	2281
IE	1604	1025	9919	0	73	600	735	985	17418
IT	22615	50983	114245	0	4967	0	44408	60278	44223
LV	940	3342	2545	0	187	0	1	104	1594
LT	1383	614	4567	11076	56	0	0	0	390
LU	439	140	1881	0	0	0	418	0	459

Country	Biomass Waste (GWh)	Hydro (GWh)	Natural Gas (GWh)	Nuclear (GWh)	Oil (GWh)	Other (GWh)	Solar (GWh)	Solids Fired (GWh)	Wind (GWh)
MT	49	0	1398	0	30	0	394	0	429
NL	11486	106	46038	4973	2008	0	1034	34237	34532
PL	7012	4812	11520	48565	527	0	571	125226	17084
PT	5331	11898	6275	0	117	839	10905	258	21390
RO	1656	22413	11327	14875	1946	0	2130	16066	7831
SK	1074	6144	2520	26441	51	0	1115	2818	882
SI	631	4621	2542	5785	0	0	473	3610	633
ES	10370	35967	91383	57733	2530	58	35906	33978	90621
SE	20745	69694	640	73830	515	0	239	1347	13224
UK	17993	5392	136962	34923	2246	3909	8907	9629	151832

Table A.2: Wholesale electricity price by Member State as simulated for 2013 PRIMES REF for the year 2030

Country	Price (€2010/MWh)	Country	Price (€2010/MWh)
AT	89	**IE**	84
BE	89	**IT**	96
BG	92	**LT**	85
CY	111	**LU**	86
CZ	86	**LV**	85
DE	88	**MT**	111
DK	83	**NL**	92
EE	82	**PL**	96
ES	94	**PT**	93
FI	82	**RO**	97
FR	85	**SE**	85
GR	97	**SI**	87
HR	90	**SK**	92
HU	94	**UK**	94

Table A.3: Capacity factor of natural gas CCGT generation as simulated for 2013 PRIMES REF for the year 2030

Country	Capacity Factor (%)
AT	3.3
BE	61.4
BG	82.4
CY	57.7
CZ	0.4
DE	43.6
DK	0
EE	18.6
ES	34.7
FI	0.9
FR	5.6
GR	53.3
HR	64
HU	1.3

Country	Capacity Factor (%)
IE	50.3
IT	30.2
LT	1.1
LU	0
LV	1.4
MT	65.8
NL	10
PL	26.4
PT	11.8
RO	32.7
SE	2
SI	47
SK	7.6
UK	35.8

Table A.4: Variable renewable curtailment as simulated for 2013 PRIMES REF for the year 2030

Country	Curtailment (%)
AT	0
BE	0
BG	0
CY	6.219748
CZ	0
DE	0.004583
DK	0
EE	0
ES	0.010289
FI	0

Country	Curtailment (%)
FR	0.005553
GR	0
HR	0
HU	0
IE	11.00376
IT	0.014738
LT	0
LU	0
LV	0

Appendix B

This appendix provides more detailed description of the model and data developed as well as extended results of the analysis in chapter 5.

Availability of Models and Data

The PLEXOS model used in this study is available at:

https://energyexemplar.com/

The Renewables.ninja PV and wind generation dataset is available at:

https://www.renewables.ninja/downloads

Models and Their Assumptions

While all modelling assumptions and data sources underpinning this work have been provided in the manuscript, this section serves to more thoroughly detail the models used to provide further information for the reader regarding the underlying assumptions and implicit limitations of this study. The methodology applied in this work for the development of the power system model is a soft-linked methodology as described in section 3.4.1 of chapter 3.

PLEXOS Integrated Energy Model

PLEXOS Integrated Energy Model is a power system modelling platform developed by Energy Exemplar that is used for integrated modelling of power, gas and water systems (Energy Exemplar, 2018a). It is a commercial modelling tool that is free of charge for non-commercial research applications in academic institutions.

The model minimises the total generation cost of the system while respecting four key constraints: 1) electricity demand and supply must balance; 2) technical characteristics of generators (such as minimum stable levels, ramp rates, minimum up and down times, and maintenance rates); 3) transmission capacity of interconnector lines; 4) forced (random outages based on Monte Carlo simulations) and unforced (scheduled) outages of generators.

The model was simulated using the MOSEK solver with rounded relaxation unit commitment, a duality gap of 0.05% and a six hour look ahead. In line with the EU Target

Model day-ahead market-scheduling algorithm, known as EUPHEMIA (N-Side, 2016) 365 days of the each scenario simulation year were simulated at hourly resolution.

In PLEXOS the formulation that is applied to each generator unit is customised depending on the data and options defined. For completeness, here serves to describe a "typical" formulation for generation units.

Indices

t	Dispatch interval
i	Generating unit
k	Run up or run down interval

Decision variables

$GenLoad_{i,t}$	Load of generating unit i at the end of dispatch interval t
$GenOn_{i,t}$	Binary (0,1) variable indicating if generating unit i is operating during dispatch t
$GenStart_{i,t}$	Binary (0,1) variable indicating if generating unit i started in dispatch interval t
$GenStop_{i,t}$	Binary (0,1) variable indicating if generating unit i shut down at the beginning of dispatch period t

Data

$[Rating]_{i,t}$	Rating of generating units i in period t
$[MaxCapacity]_{i}$	Maximum power of generating unit i

[MinStableLevel]$_i$	Minimum stable level of generating unit i
[RunUpTime]$_i$	Number of intervals that generating unit i takes a run up
[StartProfile]$_{i,k}$	Generating unit i load in run up interval k
[RunDownTime]$_i$	Number of intervals that generating unit i takes to run down
[ShutdownProfile]$_{i,k}$	Generating unit i load in run down interval k

Formulation

Generator rating – Generator load mustn't exceed the maximum rating of the unit:

$$GenLoad_{i,t} - [Rating]_{i,t} * GenOn_{i,t} \leq \ 0 \ \forall \mathrm{i}, \mathrm{t}$$

Generator maximum with run up – Generator load cannot be greater than maximum power or exceed the relevant start profile during the run-up period:

$$GenLoad_{i,t} - [MaxCapacity]_i * GenOn_{i,t}$$

$$+ \sum_{k=1}^{[RunUpTime]_i} ([MaxCapacity]_i - [StartProfile]_{i,k})$$

$$* \, GenStart_{i,t-[RunUpTime]_{i+k}} \ \leq \ 0 \ \forall \mathrm{i}, \mathrm{t}$$

Generator minimum – Generator must be above or at the minimum stable level except during start-up or shut-down periods:

$$GenLoad_{i,t} - [MinStableLevel]_i * GenOn_{i,t}$$

$$+ \sum_{k=1}^{[RunUpTime]_i} ([MinStableLevel]_i - [StartProfile]_{i,k})$$

$$* \, GenStart_{i,t-[RunUpTime]}$$

$$+ \sum_{k=1}^{[RunDownTime]_i} ([MinStableLevel]_i - [ShutdownProfile]_{i,k})$$

$$* \, GenStop_{i,t+k-1]} \ \geq \ 0 \ \forall \mathrm{i}, \mathrm{t}$$

Definition of generator stop and start – The operating state of a unit can only change if a stop or start has occurred:

$$GenOn_{i,t} - GenOn_{i,t-1} - GenStart_{i,t} + GenSto_{i,t} = 0 \ \forall \mathrm{i}, \mathrm{t}$$

Generator minimum up-time – The generation unit mist be running if started in any dispatch interval looking back over the minimum up-time:

$$GenOn_{i,t} - \sum_{k=t-[MinUpTime]+1}^{t} GenStart_{i,k} \geq 0 \ \forall \mathrm{i}, \mathrm{t}$$

Generator minimum down-time –The generation unit must not be running if shutdown in any dispatch interval looking back over the minimum down time

$$GenOn_{i,t} - \sum_{k=t-[MinDownTime]+1}^{t} GenStop_{i,k} \leq 0 \ \forall \mathrm{i}, \mathrm{t}$$

Renewables.ninja Wind and PV Generation Datasets

The Renewables.ninja PV and wind simulation models(Pfenninger and Staffell, 2016, Staffell and Pfenninger, 2016) were used to generate hourly time series of wind and PV generation aggregated to country levels for 30 historical weather years, from 1985 to 2014.

Renewables.ninja uses the NASA MERRA-2 global meteorological reanalysis(Gelaro et al., 2017) to provide consistent weather input data for wind and PV generation. As discussed in Refs.(Staffell and Pfenninger, 2016, Pfenninger and Staffell, 2016) MERRA-2 has many advantages over other global reanalyses, in particular, it provides observations at hourly intervals and has a high spatial resolution of 0.5° latitude and 0.625° longitude(Liléo and Petrik, 2000). Reanalysis data are known to require bias correction due to systemic errors in the assimilation of data through the underlying weather model, their spatial coarseness and their representation of wind speeds at actual wind farm sites(Stickler and Brönnimann, 2011). The Renewables.ninja data are bias-corrected by validation with historic solar PV and wind generation as described in Refs.(Staffell and Pfenninger, 2016, Pfenninger and Staffell, 2016).

Renewables.ninja uses the Global Solar Energy Estimator (GSEE) model(Pfenninger and Staffell, 2016) for solar PV and the Virtual Wind Farm (VWF) model(Staffell and Green, 2014) for wind generation. GSEE was used to simulate PV power output from panels with probabilistic tilt and azimuth angles drawn from a distribution of known panel angles in Europe, in each MERRA-2 grid cell, the results of which are then aggregated to country level data. The VWF model was used to simulate specific individual wind farms in Europe, both existing and planned, the results of which are aggregated to country level. This is not possible for PV systems due to lacking information about distributed PV installations across Europe.

The resulting bias-corrected datasets show good agreement with reported aggregated generation data (see Refs.(Staffell and Pfenninger, 2016, Pfenninger and Staffell, 2016)). Future work on simulating Europe's decarbonised power system at higher spatial resolutions than the country-aggregated level used here will nevertheless benefit from using newer reanalyses with higher spatial resolution, regional reanalyses, or other more highly resolved datasets such as direct satellite-measured data.

Extended Results

Table B.2: Results overview for Europe

	2015 System	EU Reference 2030	ENTSOE Vision 1 2030	ENTSOE Vision 2 2030	ENTSOE Vision 3 2030	ENTSOE Vision 4 2030
Electricity Price[1] (€/MWh)	44 (±2.2%)	82 (±2.1%)	68 (±1.4%)	60 (±2.1%)	60 (±3.6%)	64 (±3.7%)
Wind-weighted Price (€/MWh)[2]	48 (2.2%)	81 (1.3%)	68 (1.8%)	58 (3.2%)	56 (4.4%)	63 (4.2%)
Solar-weighted Price (€/MWh)	45 (2.8%)	86 (1.7%)	66 (1.9%)	54 (2.6%)	40 (4.5%)	39 (5.7%)
Gas-weighted Price (€/MWh)	69 (2.5%)	92 (2.0%)	96 (1.4%)	105 (2.2%)	95 (1.8%)	99 (2.0%)
Coal-weighed Price (€/MWh)	50 (2.5%)	91 (1.2%)	77 (1.1%)	75 (1.2%)	128 (5.3%)	124 (3.7%)
Nuclear-weighted Price (€/MWh)	40 (2.2%)	75 (1.3%)	61 (1.3%)	54 (2.1%)	61 (3.2%)	66 (3.7%)
Total Generation Cost[3] (€B)	47.11 (±0.8%)	86.83 (±2.1%)	62.09 (±2.1%)	44.39 (±3.0%)	50.28 (±4.2%)	60.47 (±4.0%)
Total CO_2 Emissions (Mt)	1001 (±1.0%)[4]	917 (±1.3%)	713 (±2.1%)	551 (±3.0%)	233 (±5.0%)	288 (±4.7%)
Carbon Intensity (gCO_2/kWh)	322.6 (±1.0%)	247.8 (±1.3%)	209.7 (±2.1%)	167.0 (±3.0%)	68.5 (±5.0%)	80.0 (±4.7%)
RE Generation Share	36.7% (±1.0%)	47.2% (±1.4%)	51.0% (±1.3%)	57.0% (±1.3%)	68.4% (±1.3%)	67.4% (±1.3%)
VRE Generation Share	13.4% (±2.8%)	24.4% (±2.7%)	23.0% (±2.9%)	25.2% (±3.0%)	35.1% (±2.8%)	35.6% (±2.7%)
VRE Curtailment	0.1% (±26.3%)	0.1% (±16.8%)	0.3% (±18.5%)	1.6% (±14.5%)	4.3% (±10.7%)	4% (±8.8%)
Interconnector Congestion[5]	26.0% (±0.9%)	19.1% (±2.6%)	25.1% (±2.2%)	28.3% (±1.9%)	29.7% (±1.0%)	35.0% (±0.8%)
Total International Electricity Flow	267 TWh (±0.7%)	355 TWh (±2.3%)	441 TWh (±1.5%)	454 TWh (±1.6%)	411 TWh (±1.2%)	480 TWh (±0.9%)

[1] Wholesale electricity price is defined as the marginal cost of electricity in each region, reflecting the shadow price on the electricity demand-supply constraint. This captures an uplift element to account for start-up costs of thermal plant but excludes taxes, capacity payments or ancillary services. This should be interpreted as an energy-only price in a perfect wholesale market where no market power of strategic behaviours occurs.
[2] Average price received by wind generators (also referred to as 'capture price')
[3] Total Generation Cost = Generation Cost + Start & Shutdown Cost + Emissions Cost
[4] Total electricity emissions from this base year simulation is within 3% of the official verified emissions (1025 Mt) for this year, using our historical 1985-2014 weather data.
[5] Averaged over all transmission lines

Table B.3: Results overview for Germany

	2015 System	EU Reference 2030	ENTSOE Vision 1 2030	ENTSOE Vision 2 2030	ENTSOE Vision 3 2030	ENTSOE Vision 4 2030
Electricity Price (€/MWh)	46 (±6.5%)	105 (±1.9%)	78 (±2.5%)	73 (±2.3%)	59 (±5.1%)	68 (±4.6%)
Wind-weighted Price (€/MWh)	41 (6.0%)	95 (2.3%)	67 (3.7%)	64 (3.5%)	45 (7.0%)	53 (6.0%)
Solar-weighted Price (€/MWh)	39 (7.8%)	114 (2.8%)	70 (3.3%)	58 (3.9%)	39 (5.7%)	45 (6.9%)
Gas-weighted Price (€/MWh)	99 (48.8%)	115 (3.2%)	105 (5.6%)	101 (4.3%)	89 (2.5%)	93 (2.2%)
Coal-weighed Price (€/MWh)	47 (5.7%)	104 (1.9%)	83 (1.7%)	79 (1.5%)	107 (23.3%)	118 (14.4%)
Nuclear-weighted Price (€/MWh)	45 (6.2%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)
Total Generation Cost (€B)	9.16 (±1.7%)	19.70 (±2.2%)	12.61 (±3.0%)	10.77 (±3.2%)	7.66 (±7.8%)	10.01 (±6.8%)
Total CO_2 Emissions (Mt)	270 (±1.9%)	288 (±1.0%)	221 (±2.7%)	190 (±3.3%)	38 (±8.6%)	50 (±7.8%)
Carbon Intensity (gCO_2/kWh)	509.1 (±1.9%)	455.5 (±1.5%)	372.0 (±3.3%)	369.3 (±3.5%)	70.7 (±9.6%)	91.1 (±8.7%)
RE Generation Share	30.2% (±3.3%)	45.4% (±2.6%)	57.6% (±2.6%)	58.5% (±2.7%)	82.2% (±2.0%)	77.6% (±2.4%)
VRE Generation Share	22.7% (±4.4%)	36.8% (±3.4%)	41.2% (±3.9%)	37.2% (±4.3%)	58.0% (±3.3%)	56.5% (±3.6%)
VRE Curtailment	0.0% (±0%)	0.0% (±0%)	0.4% (±27.4%)	0.3% (±28.7%)	7.9% (±12.4%)	7.9% (±8.2%)
Interconnector Congestion	25.1% (±1.8%)	16.4% (±4.2%)	24.4% (±4.0%)	22.3% (±3.6%)	31.7% (±2.1%)	32.6% (±1.9%)
Total International Electricity Flow	53 TWh (±1.6%)	79 TWh (±3.6%)	105 TWh (±3.0%)	100 TWh (±2.7%)	109 TWh (±1.9%)	121 TWh (±1.6%)

Table B.4 - Results overview for Spain

	2015 System	EU Reference 2030	ENTSOE Vision 1 2030	ENTSOE Vision 2 2030	ENTSOE Vision 3 2030	ENTSOE Vision 4 2030
Electricity Price (€/MWh)	52 (±1.9%)	81 (1.4%)	76 (±1.5%)	68 (±2.3%)	71 (±3.5%)	68 (±4.9%)
Wind-weighted Price (€/MWh)	47 (2.7%)	76 (1.6%)	69 (1.6%)	63 (2.9%)	64 (3.8%)	63 (5.1%)
Solar-weighted Price (€/MWh)	49 (1.6%)	72 (1.4%)	64 (1.8%)	43 (3.3%)	48 (4.4%)	30 (6.4%)
Gas-weighted Price (€/MWh)	57 (1.9%)	88 (2.6%)	95 (2.7%)	100 (3.4%)	85 (2.7%)	91 (3.9%)
Coal-weighed Price (€/MWh)	52 (1.9%)	83 (1.1%)	79 (1.3%)	79 (1.8%)	92 (27.2%)	113 (24.5%)
Nuclear-weighted Price (€/MWh)	51 (1.8%)	81 (1.3%)	75 (1.3%)	69 (2.4%)	72 (3.5%)	73 (4.8%)
Total Generation Cost (€B)	4.03 (±2.3%)	6.42 (±3.5%)	5.92 (±2.9%)	4.23 (±3.5%)	8.88 (±2.5%)	8.85 (±2.5%)
Total CO_2 Emissions (Mt)	76 (±2.2%)	50 (±2.5%)	66 (±2.1%)	48 (±3.1%)	42 (±3.0%)	39 (±3.2%)
Carbon Intensity (gCO_2/kWh)	315.4 (±2.3%)	182.1 (±2.6%)	221.8 (±2.3%)	168.5 (±3.1%)	121.3 (±3.0%)	104.1 (±3.2%)
RE Generation Share	42.0% (±2.5%)	52.7% (±2.1%)	52.0% (±1.8%)	61.4% (±1.3%)	55.9% (±1.6%)	61.7% (±1.4%)
VRE Generation Share	25.1% (±4.2%)	36.8% (±3.2%)	34.7% (±2.9%)	38.5% (±2.2%)	35.9% (±2.7%)	43.1% (±2.0%)
VRE Curtailment	0.2% (±52.5%)	0.1% (±45.4%)	0.2% (±36.8%)	1.2% (±15.5%)	0.8% (±20.9%)	0.8% (±56.2%)
Interconnector Congestion	20.2% (±7.2%)	9.6% (±12.4%)	11.2% (±10.6%)	18.1% (±7.0%)	11.3% (±11.6%)	6.6% (±13.5%)
Total International Electricity Flow	10 TWh (±4.1%)	28 TWh (±5.5%)	34 TWh (±4.0%)	37 TWh (±3.6%)	28 TWh (±5.8%)	17TWh (±6.8%)

Table B.5: Results overview for France

	2015 System	EU Reference 2030	ENTSOE Vision 1 2030	Vision 2 2030	Vision 3 2030	Vision 4 2030
Electricity Price (€/MWh)	38 (±2.3%)	74 (±1.7%)	59 (±1.4%)	53 (±2.5%)	60 (±4.2%)	64 (±5.0%)
Wind-weighted Price (€/MWh)	36 (3.2%)	70 (1.5%)	56 (1.8%)	49 (3.5%)	51 (5.6%)	55 (6.6%)
Solar-weighted Price (€/MWh)	34 (1.7%)	71 (1.1%)	54 (1.5%)	44 (3.2%)	39 (5.9%)	38 (6.5%)
Gas-weighted Price (€/MWh)	77 (14.7%)	98 (12.4%)	97 (12.5%)	93 (6.6%)	86 (3.4%)	89 (3.6%)
Coal-weighed Price (€/MWh)	44 (2.9%)	75 (1.1%)	64 (1.3%)	64 (2.1%)	72 (19.6%)	89 (23.5%)
Nuclear-weighted Price (€/MWh)	37 (2.0%)	74 (1.5%)	60 (1.3%)	53 (2.5%)	62 (3.9%)	66 (4.7%)
Total Generation Cost (€B)	2.97 (±0.9%)	4.18 (±1.6%)	3.27 (±1.4%)	2.88 (±1.4%)	3.59 (±5.3%)	4.18 (±5.8%)
Total CO_2 Emissions (Mt)	16 (±3.8%)	29 (±2.1%)	16 (±3.7%)	10 (±5.8%)	11 (±9.2%)	13 (±9.1%)
Carbon Intensity (gCO_2/kWh)	29.9 (±3.8%)	46.6 (±2.4%)	29.7 (±3.9%)	18.5 (±5.8%)	21.5 (±9.2%)	25.8 (±9.3%)
RE Generation Share	19.9% (±0.9%)	32.8% (±1.2%)	27.4% (±1.2%)	25.1% (±0.9%)	45.2% (±1.3%)	46.4% (±1.6%)
VRE Generation Share	5.4% (±3.5%)	18.1% (±2.5%)	13.1% (±2.8%)	8.3% (±2.9%)	26.2% (±2.5%)	28.2% (±2.8%)
VRE Curtailment	0.0% (±0%)	0.0% (±0%)	0.1% (±56.6%)	0.5% (±42.0%)	1.2% (±23.5%)	1.2% (±27.4%)
Interconnector Congestion	47.1% (±1.8%)	46.3% (±2.7%)	47.4% (±2.5%)	41.3% (±1.9%)	23.1% (±4.8%)	22.7% (±4.8%)
Total International Electricity Flow	47 TWh (±1.1%)	81 TWh (±2.7%)	92 TWh (±2.4%)	75 TWh (±1.5%)	57 TWh (±5%)	46 TWh (±5.2%)

Table B.6: Results overview for Italy

	2015 System	EU Reference 2030	ENTSOE Vision 1 2030	Vision 2 2030	Vision 3 2030	Vision 4 2030
Electricity Price (€/MWh)	58 (±0.9%)	85 (±1.1%)	90 (±1.0%)	83 (±1.6%)	72 (±2.2%)	76 (±3.1%)
Wind-weighted Price (€/MWh)	55 (1.0%)	85 (1.4%)	85 (1.3%)	77 (2.1%)	64 (3.8%)	68 (3.1%)
Solar-weighted Price (€/MWh)	56 (1.2%)	82 (0.8%)	76 (1.4%)	65 (2.0%)	39 (3.9%)	44 (5.3%)
Gas-weighted Price (€/MWh)	60 (1.1%)	90 (2.0%)	108 (1.5%)	112 (1.7%)	94 (2.0%)	93 (2.2%)
Coal-weighed Price (€/MWh)	56 (0.9%)	86 (1.1%)	88 (1.0%)	84 (1.3%)	100 (22.7%)	110 (18.1%)
Nuclear-weighted Price (€/MWh)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)
Total Generation Cost (€B)	6.93 (±0.8%)	11.7 (±1.4%)	9.93 (±1.0%)	7.18 (±1.6%)	7.78 (±2.3%)	10.09 (±2.1%)
Total CO_2 Emissions (Mt)	97 (±0.5%)	80 (±1.0%)	94 (±0.8%)	77 (±1.3%)	38 (±2.9%)	49 (±2.5%)
Carbon Intensity (gCO_2/kWh)	362.3 (±0.5%)	272.2 (±0.9%)	305.8 (±0.6%)	263.6 (±0.9%)	129.0 (±2.3%)	147.6 (±2.0%)
RE Generation Share	41.2% (±1.0%)	46.6% (±1.3%)	49.5% (±0.9%)	59.6% (±0.8%)	55.9% (±1.6%)	69.2% (±1.0%)
VRE Generation Share	15.3% (±2.7%)	21.5% (±2.9%)	34.7% (±2.9%)	21.3% (±2.1%)	35.9% (±2.7%)	30.3% (±2.1%)
VRE Curtailment	0% (±0%)	0% (±0%)	0% (±0%)	0.5% (±20.8%)	4.2% (±8.6%)	4.2% (±7.8%)
Interconnector Congestion	48.9% (±2.1%)	60.1% (±2.4%)	48.1% (±2.3%)	36.6% (±4.3%)	37.8% (±3.9%)	42.2% (4.2%)
Total International Electricity Flow	48 TWh (±1.3%)	61 TWh (±2.9%)	49 TWh (±3.1%)	45 TWh (±4.1%)	11 TWh (±8.0%)	31TWh (±6.3%)

Table B.7: Results overview for Great Britain

	2015 System	EU Reference 2030	ENTSOE Vision 1 2030	Vision 2 2030	Vision 3 2030	Vision 4 2030
Electricity Price (€/MWh)	59 (±1.6%)	79 (±1.3%)	81 (±1.2%)	55 (±5.4%)	60 (±4.5%)	61 (±5.2%)
Wind-weighted Price (€/MWh)	56 (±1.9%)	76 (±1.3%)	77 (±1.3%)	43 (±6.7%)	47 (±5.7%)	47 (±6.3%)
Solar-weighted Price (€/MWh)	54 (±2.9%)	78 (±1.4%)	77 (±1.9%)	54 (±5.0%)	43 (±5.8%)	47 (±5.7%)
Gas-weighted Price (€/MWh)	67 (±1.5%)	84 (±1.8%)	86 (1.4%)	83 (4.1%)	87 (2.5%)	89 (2.7%)
Coal-weighed Price (€/MWh)	59 (±1.6%)	80 (±1.0%)	83 (±1.3%)	78 (±3.5%)	47 (±5.7%)	0 (±0%)
Nuclear-weighted Price (€/MWh)	58 (±1.4%)	79 (±1.2%)	80 (±1.2%)	60 (±3.7%)	66 (±3.0%)	68 (±3.5%)
Total Generation Cost (€B)	6.56 (±1.5%)	8.82 (±5.5%)	10.46 (±2.8%)	3.56 (±10.5%)	6.19 (±7.9%)	6.60 (±8.7%)
Total CO_2 Emissions (Mt)	146 (±1.3%)	40 (±6.0%)	70 (±2.9%)	25 (±10.6%)	28 (±9.2%)	29 (±9.8%)
Carbon Intensity (gCO_2/kWh)	523.2 (±1.3%)	109.7 (±6.0%)	249.9 (±2.8%)	80.4 (±11.8%)	76.6 (±9.5%)	77.5 (±10.2%)
RE Generation Share	22.2% (±4.2%)	49.9% (±3.4%)	32.9% (±5.0%)	76.3% (±2.9%)	65.6% (±3.6%)	67.4% (±3.6%)
VRE Generation Share	17.7% (±5.6%)	31.9% (±5.4%)	27.3% (±6.0%)	64.3% (±3.7%)	52.5% (±4.7%)	56.6% (±4.4%)
VRE Curtailment	0% (±0%)	0% (±0%)	0% (±0%)	4.3% (±15.7%)	2.7% (±16.9%)	2.7% (±18.0%)
Interconnector Congestion	35.9% (±2.0%)	29.8% (±3.2%)	39.9% (±2.3%)	51.0% (±2.3%)	36.3% (±2.0%)	44.0% (1.6%)
Total International Electricity Flow	18 TWh (±1.6%)	42 TWh (±3.1%)	58 TWh (±1.7%)	60 TWh (±1.7%)	45 TWh (±1.7%)	52TWh (±1.5%)

Wind and Solar Output Variability

This section shows the variability of annual capacity factors for wind and solar profiles by country for all scenarios considered. For all diagrams, the text on each country describes the mean capacity factor followed by the percentage point standard deviation over the course of all 30 weather years. The colour scale indicates the mean capacity factor for either wind or solar PV in each country.

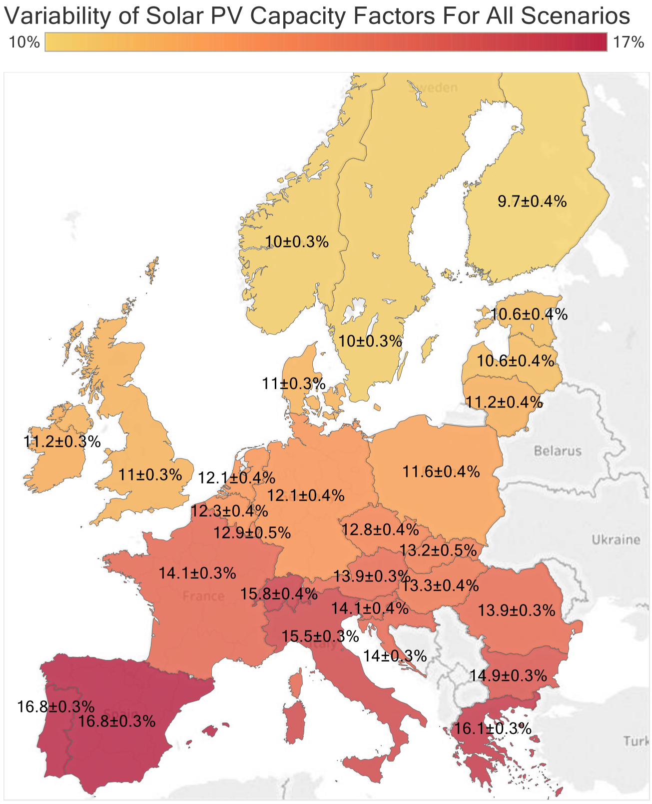

Figure B.1: Solar capacity factor variability for all scenarios considered

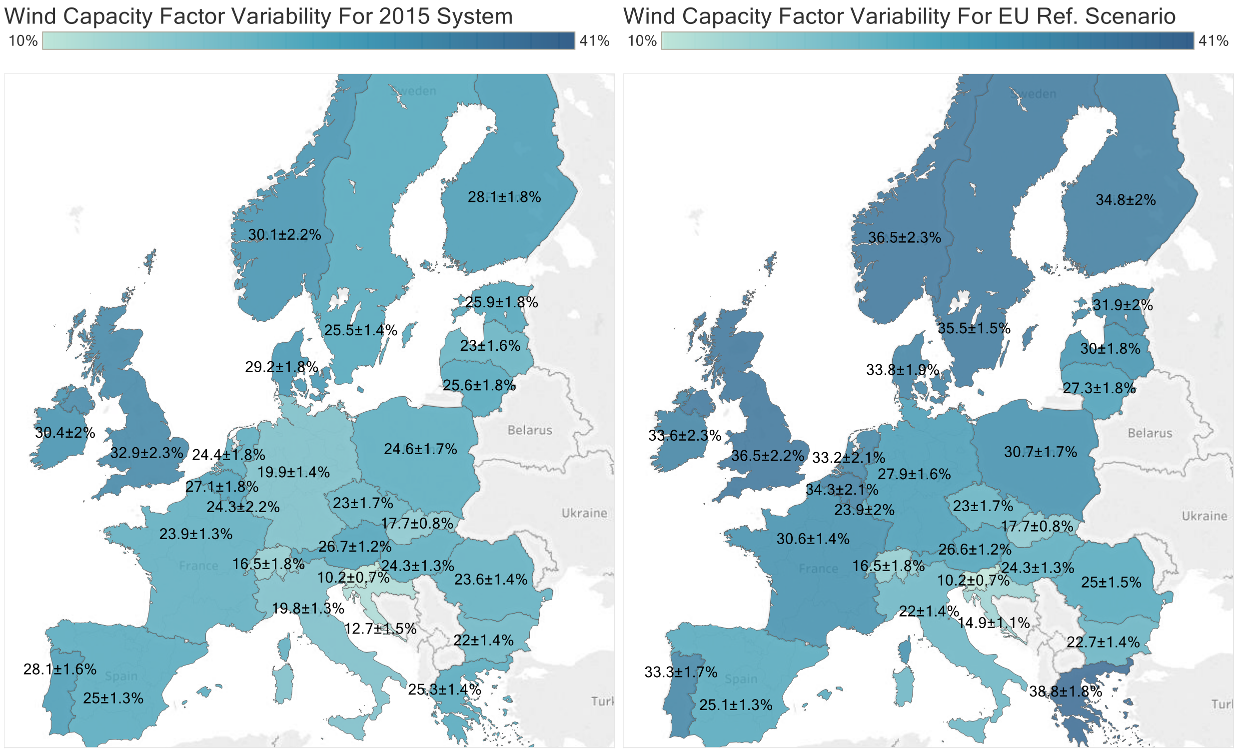

Figure B.2: Wind capacity factor variability for 2015 System and EU Reference Scenario

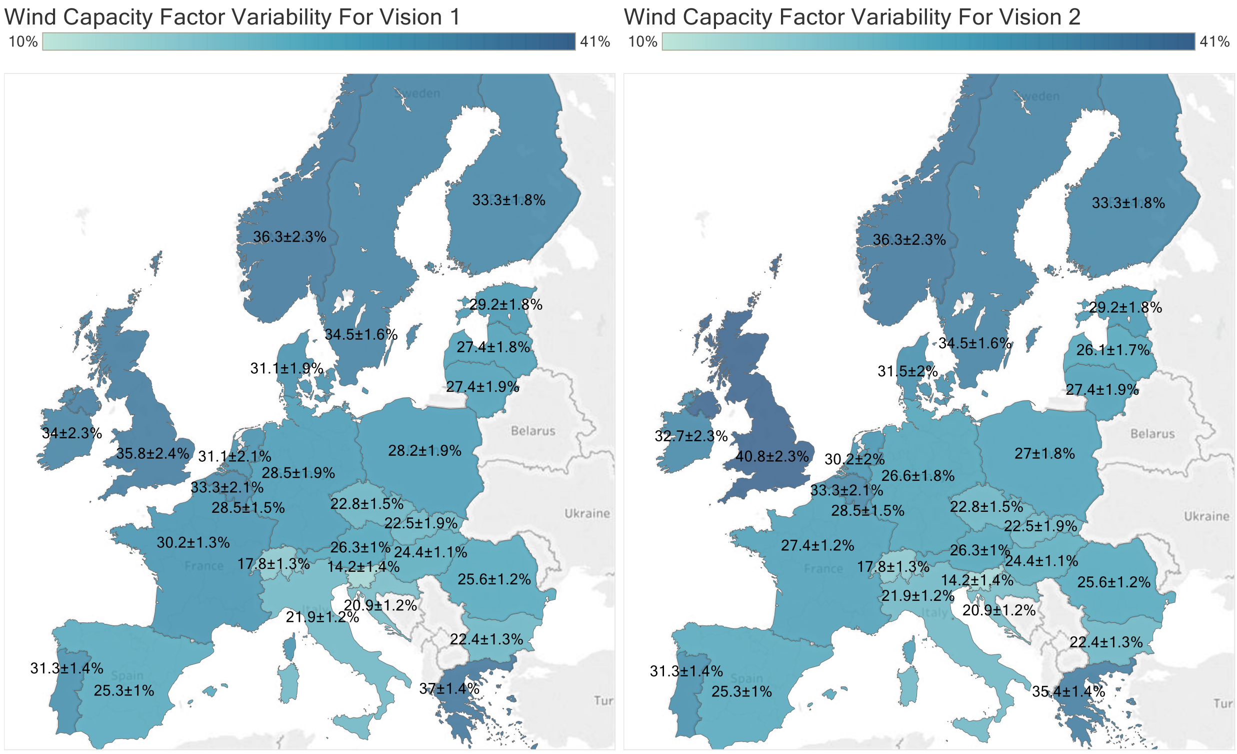

Figure B.3: Wind capacity factor variability for Vision 1 and Vision 2

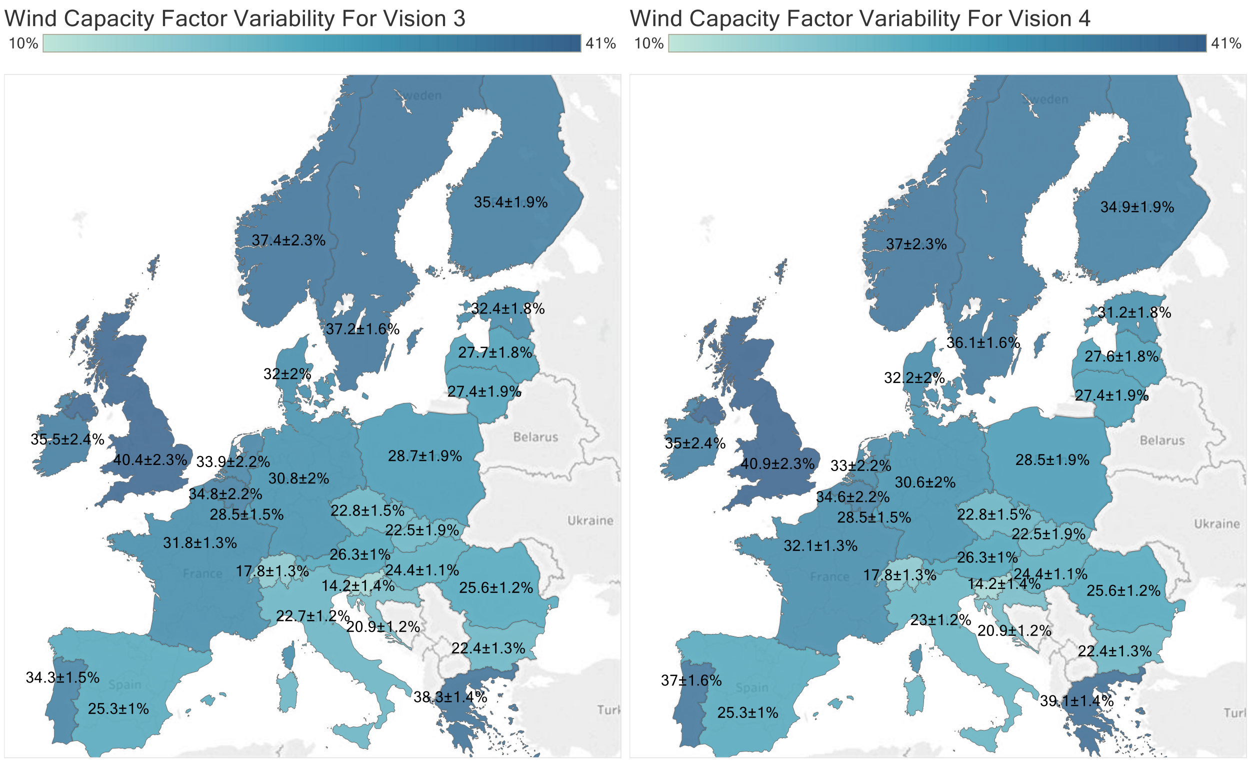

Figure B.4: Wind capacity factor variability for Vision 3 and Vision 4

Most representative single years

The below table details the root mean squared error across eight metrics for all weather years considered. This error is determined as the RMS difference between each year and the long-run mean for each metric normalised by the long-run mean.

Table B.8: Root mean squared error across various metrics for all weather years

Weather Year	VRE Penetration	CO_2 Emissions	Total Generation Costs	Market Prices	RE Penetration	IC Congestion	Total IC Flow	VRE Curtailment	Average RMS Error
1985	3.4%	3.7%	3.4%	1.2%	0.6%	2.2%	1.6%	3.3%	2.43%
1986	2.8%	2.6%	2.9%	1.2%	1.5%	0.7%	0.5%	12.3%	3.05%
1987	4.8%	4.8%	4.4%	1.9%	1.6%	1.7%	1.8%	12.3%	4.16%
1988	2.5%	2.7%	2.6%	1.2%	1.9%	1.2%	0.9%	3.9%	2.11%
1989	0.7%	0.6%	0.5%	0.9%	0.8%	1.0%	0.5%	0.9%	0.72%
1990	4.8%	4.7%	4.4%	2.8%	1.0%	2.4%	2.3%	24.2%	5.82%
1991	1.2%	1.3%	1.2%	1.0%	1.6%	0.3%	0.4%	9.2%	2.04%
1992	2.0%	1.8%	1.6%	1.1%	0.7%	0.7%	0.3%	16.4%	3.08%
1993	2.1%	2.2%	2.1%	1.5%	0.9%	1.2%	1.3%	7.3%	2.32%
1994	3.6%	3.4%	3.2%	2.8%	1.1%	1.5%	1.3%	19.2%	4.50%
1995	3.4%	3.3%	3.3%	2.5%	1.6%	1.9%	1.4%	1.3%	2.32%
1996	1.1%	1.4%	0.7%	1.0%	1.2%	0.7%	0.6%	14.4%	2.65%
1997	2.5%	2.8%	2.8%	1.3%	0.8%	0.9%	0.5%	8.5%	2.52%
1998	4.8%	4.9%	4.5%	2.9%	1.5%	1.8%	1.8%	12.3%	4.32%
1999	2.1%	1.8%	2.0%	1.4%	1.7%	1.1%	0.6%	3.7%	1.80%
2000	3.0%	2.9%	2.7%	1.4%	1.1%	2.2%	1.7%	2.0%	2.13%
2001	1.2%	1.3%	0.9%	0.5%	1.1%	1.1%	1.0%	4.9%	1.50%
2002	0.5%	0.7%	0.6%	0.6%	0.4%	0.7%	0.7%	4.3%	1.07%
2003	3.7%	3.9%	3.5%	2.1%	0.8%	2.4%	2.4%	9.6%	3.55%
2004	0.9%	0.9%	1.1%	0.7%	1.3%	0.6%	0.3%	7.4%	1.64%
2005	0.6%	0.8%	0.6%	0.5%	0.3%	0.5%	1.0%	6.3%	1.34%
2006	2.9%	2.7%	2.6%	2.0%	0.6%	1.6%	1.3%	8.4%	2.76%
2007	1.6%	1.7%	1.4%	1.4%	1.1%	2.0%	1.9%	2.8%	1.73%
2008	1.6%	2.1%	2.1%	1.7%	0.8%	0.7%	0.8%	4.3%	1.77%
2009	2.5%	2.6%	2.2%	1.3%	0.9%	1.8%	1.5%	9.3%	2.75%
2010	5.9%	5.6%	5.3%	3.1%	1.7%	2.2%	1.8%	26.1%	6.45%
2011	0.4%	0.3%	0.3%	0.6%	1.8%	0.5%	0.4%	7.3%	1.44%
2012	0.9%	0.6%	0.7%	0.6%	0.3%	0.4%	0.3%	3.7%	0.92%
2013	1.1%	1.3%	1.0%	0.5%	0.5%	1.1%	0.6%	3.9%	1.24%
2014	2.0%	1.5%	3.2%	8.1%	0.6%	0.5%	0.7%	12.0%	3.58%

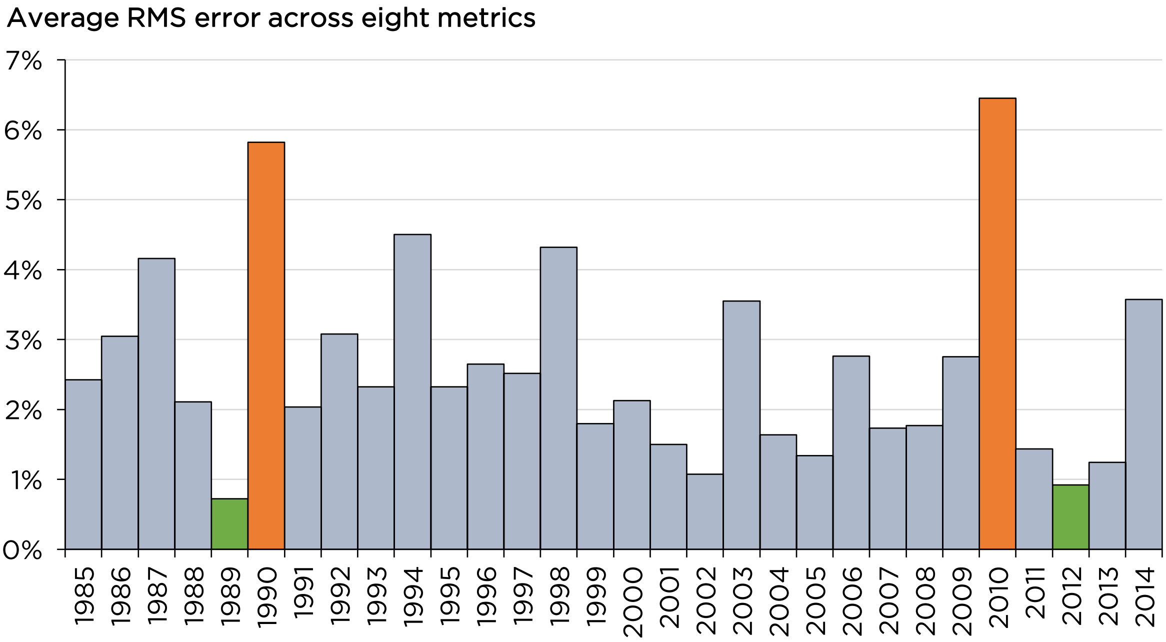

Figure B.5: Average RMS Error across eight metrics

Appendix C

This appendix provides more detailed description of data developed as well as results of the analysis in chapter 6.

Table C.1: Gross Electricity Demand in both the REmap and Reference scenarios considered for 2030

	REmap 2030 (GWh)	Reference 2030 (GWh)		REmap 2030 (GWh)	Reference 2030 (GWh)
AT	91,458	85,004	**IE**	36,141	33,441
BE	103,710	100,415	**IT**	447,876	426,473
BG	38,274	37,131	**LT**	13,086	12,150
CH	69,606	69,606	**LU**	11,310	9,963
CY	9,540	6,871	**LV**	11,404	9,739
CZ	82,891	77,304	**MT**	3,249	3,096
DE	625,037	585,650	**NL**	121,579	115,602
DK	52,107	43,115	**NO**	131,946	131,946
EE	10,625	9,853	**PL**	206,792	203,236
ES	329,229	308,232	**PT**	61,349	57,130
FI	104,193	99,677	**RO**	64,547	60,338
FR	481,889	477,144	**SE**	160,716	158,335
GR	62,981	60,195	**SI**	18,759	18,012
HU	50,140	46,738	**SK**	39,602	37,071
HR	20,928	19,620	**UK**	478,479	419,107

Table C.2: Total installed electricity generation capacity in the REmap Scenario for the year 2030 in Megawatts

	Biomass waste (MW)	Biogas (MW)	Geothermal (MW)	Hydro (MW)	Solar (MW)	Wind (MW)	Natural gas (MW)	Nuclear (MW)	Oil (MW)	Other (MW)	Coal (MW)
AT	901		2	13,741	3,856	5,506	2,891		423		542
BE	2,063			300	11,221	4,370	11,543				960
BG	101			2,338	3,987	2,774	1,043	1,920	2		3,176
CY	28			-	1,350	336	940				
CZ	274		0	1,109	3,362	1,000	1,616	4,006	64		8,818
DE	20,000		646	5,355	75,245	87,926	30,000		2,000		34,399
DK	2,401	806		12	2,537	11,144	887		1,655	170	2,593
EE	154			8	379	694	330				1,343
ES	1,902			16,795	32,895	31,559	28,096	7,399	2,952		3,030
FI	3,058			3,444	2,795	2,588	3,495	3,398	616		2,012
FR	4,200	500	400	25,900	31,100	33,500	11,900	43,400	1,400	100	2,500
GR	232			3,579	6,000	6,763	4,738		755		2,637
HR	28			2,190	658	945	1,169		107		636
HU	357		52	57	1,204	585	2,533	4,522	5		347
IE	207			261	478	4,920	3,165		173		820
IT	4,534	2,720	1,855	16,925	43,539	19,943	42,762		6,416		2,915
LT	140			116	501	571	1,315	1,117	0		
LU	35			45	142	309	681		2		
LV	111			1,589	271	398	1,068		15		
MT	2			-	348	6	675		144		
NL	2,311			37	7,474	11,363	9,334	485	66		4,911
NO				38,900		2,080	425				
PL	6,286	1,380		1,572	4,984	16,966	3,700	4,800	582		22,619
PT	664			9,971	3,252	7,057	4,224		732		
RO	157			6,645	3,997	6,881	3,971	2,828	676		1,777
SE	5,690			19,570	6,576	7,412	1,025	10,143			
SI	118			1,220	977	243	400	700	16		624
SK	322			1,718	951	800	1,046	4,020	84		486
UK	5,603		2,775	4,147	24,250	60,142	34,985	8,131	560	888	

Table C.3: Total installed electricity generation capacity in the Reference Scenario for the year 2030

	Biomass waste (MW)	Biogas (MW)	Geothermal (MW)	Hydro (MW)	Solar (MW)	Wind (MW)	Natural gas (MW)	Nuclear (MW)	Oil (MW)	Other (MW)	Coal (MW)
AT	901		2	13,741	2,754	4,235	2,892		423		774
BE	2,000			300	5,000	2,200	13,380				1,000
BG	101			2,338	2,215	2,134	1,043	1,920	2		3,263
CY	28			-	559	250	1,100				
CZ	274		0	1,109	2,242	485	1,616	4,006	64		8,855
DE	20,000		200	4,500	62,000	59,000	30,000		2,000		44,000
DK	1,640	806		12	2,537	8,564	1,045		1,655		2,910
EE	154			8	1	579	330				1,357
ES	1,902			16,795	23,497	28,690	28,096	7,399	2,952		3,968
FI	3,058			3,444	19	2,157	3,495	3,398	616		2,101
FR	3,500	500	400	25,900	25,900	27,100	13,800	44,400	1,400		3,700
GR	232			3,579	5,718	5,636	4,738		755		2,799
HR	28			2,190	365	727	1,169		107		658
HU	357		52	57	101	468	2,533	4,522	5		347
IE	207			261	17	4,100	3,165		173		842
IT	2,013	2,720	963	13,559	24,557	19,236	44,914		6,416		7,793
LT	140			116	64	408	1,344	1,117	0		
LU	35			45	129	281	682		2		
LV	111			1,589	2	285	1,091		15		21
MT	2			-	193	5	677		144		
NL	2,311			37	5,338	10,330	9,334	485	66		5,054
NO				38,900		2,080	425				
PL	3,202	1,380		1,151	2,664	7,508	3,700	4,800	582		28,949
PT	664		29	9,971	2,323	6,137	4,368		732		
RO	157			6,645	2,221	5,293	3,971	2,828	676		1,909
SE	5,181			16,659	-	7,412	1,025	11,949			
SI	118			1,220	698	187	400	700	16		632
SK	322			1,718	679	21	1,097	4,020	84		486
UK	5,603			1,952	16,000	26,912	44,516	12,963	560		

Table C.4 Efficiency of gross thermal power generation by Member State in both the REmap and Reference scenarios considered for the year 2030

	Efficiency of gross thermal power generation (%)
AT	39.2
BE	52.5
BG	39.6
CY	61.7
CZ	33.5
DE	42.0
DK	33.7
EE	33.8
ES	44.2
FI	38.0
FR	34.0
GR	43.2
HR	45.1
HU	32.6

	Efficiency of gross thermal power generation (%)
IE	47.9
IT	46.9
LT	37.7
LU	54.0
LV	42.3
MT	62.0
NL	44.8
PL	38.8
PT	39.0
RO	40.1
SE	37.9
SI	36.6
SK	26.9
UK	46.7

Table C.5: Fuel pricing used in chapter 6 in both the REmap and Reference scenarios considered for the year 2030

	Oil (€2012/GJ)	Coal (€2012/GJ)	Natural Gas (€2012/GJ)	Nuclear Fuel (€2012/GJ)	CO_2 Price (€2012/t)
AT	16.5	3.2	6.8	1.6	25
BE	15	3.2	6.8	1.6	25
BG	16.8	3.2	6.2	1.6	25
CY	16.8	3.2	7.7	1.6	25
CZ	11.1	3.2	7.7	1.6	25
DE	14.6	3.4	7.7	1.6	25
DK	16.6	3.2	4.5	1.6	25
EE	16.8	3.2	6.7	1.6	25
ES	14.8	3.2	7.4	1.6	25
FI	16.8	3.3	5.1	1.6	25
FR	15.3	3.5	7.9	1.6	25
GR	16.5	3.2	6.5	1.6	25
HR	16.8	3.2	9	1.6	25
HU	14.9	3.2	7.3	1.6	25
IE	18.6	2.6	6.7	1.6	25
IT	16.2	3.6	7.1	1.6	25
LT	16.8	3.2	8.6	1.6	25
LU	16.8	3.2	9.5	1.6	25
LV	16.8	3.2	6.5	1.6	25
MT	16.8	3.2	7.7	1.6	25
NL	14.4	3.2	5.6	1.6	25
PL	15	3	8	1.6	25
PT	19.2	2.9	7.3	1.6	25
RO	16.8	3.2	2.8	1.6	25
SE	32	3.2	7.9	1.6	25
SI	16.8	3.2	9	1.6	25
SK	12.8	3.2	8.1	1.6	25
UK	16.8	3.4	5.5	1.6	25